Bulk power facilities Eastern Ontario

Supplementary Information
March 1979

BULK POWER FACILITIES - EASTERN ONTARIO
SUPPLEMENTARY INFORMATION

INTRODUCTION

In January 1979, Ontario Hydro forwarded a submission entitled "Requirement for Additional Bulk Power Facilities in Eastern Ontario" to the Royal Commission on Electric Power Planning. The Commission, in conducting an initial review of the submission, concluded that additional clarifying information would be useful, particularly as many readers would not have ready access to the evidence previously given by Ontario Hydro to the Commission. This document has been prepared to answer certain questions addressed to Ontario Hydro by the Commission in connection with the upcoming Eastern Ontario hearings. It is hoped that the answers will assist in understanding Ontario Hydro's approach in assessing future load growth, some of the technical information and references in the submission, and the factors affecting the capability of the power system to supply load.

This document also contains the following data based on the Ontario Hydro 1979 load forecast.

Appendix A 1979 East System Load Forecast

Appendix B Table: Forecast of Ottawa Area Station Loads Coincident with January Peak (update of Figure 10 of submission of January, 1979)

Appendix C Graph of Capability of Bulk Power Transmission System to Supply Ottawa Area Loads for 1979 Load Forecast (update of Figure 24 of the submission of January 1979).

Appendix D Forecast of December Peak Loads for the Six Operating Areas in the Study Area.

As outlined in the Commission's terms of reference, the regional hearings in Eastern Ontario will deal with:

1. the electrical load growth in eastern Ontario to 1987 and from 1987 to year 2,000;

2. the capability of existing and committed bulk power generating and transmission facilities to supply this load to the area, taking into account government policy with respect to use of interconnections with neighbouring utilities; and

3. the resulting date at which additional bulk power facilities if any, will be needed.

The Commission is not required to report on the specific nature of any additional bulk power facilities that may be required, nor the location and environmental aspects of such facilities, and has indicated that it will not hear submissions on those topics. In the event that the Commission finds that additional facilities will be needed, these aspects would be reviewed at a subsequent date in accordance with the Environmental Assessment Act.

Question 1: Does Ontario Hydro's load forecasting process use estimates of various factors such as population growth rates, growth in households (including type of housing and heating), commercial manufacturing and industrial growth and the related uses of electricity, and technological change in the use of electricity in order to forecast electrical growth? If so, could such estimates be provided.

Answer: Estimates of such factors, and their relationship to electrical growth, represent the type of information which is useful when an end-use or explanatory approach is being used in forecasting. This has not been the approach taken by Ontario Hydro, with the result that the data gathered for Ontario Hydro's load forecasting is not of this type and has not been organized in this way.

However, the load forecasting methodology used by Ontario Hydro does rely heavily on estimates of local load growth provided by Hydro's wholesale customers (the municipal utilities), by direct industrial customers and by Ontario Hydro's regional offices (for retail areas serviced directly by Ontario Hydro). Embedded in these estimates are judgements based on first hand knowledge of the demand for electricity and local activites, and factors or trends which will change these demands. During its participation in the regional hearings, it is intended that Ontario Hydro's regional personnel will be presenting, for discussion with the Commission, the local information which appears most pertinent to load growth in certain key areas in Eastern Ontario.

The load growth estimates prepared at the local level are examined by the regional office staff for consistency and accuracy and any apparent anomalies are reviewed with the reporting agency. The estimates are then aggregated and the totals are examined by head office staff for consistency,

including consistency with general economic conditions. Also at this point computer calculations are done to produce a system forecast which is used for comparative purposes. The computer models used for these calculations assist in assessing the varying influences of alternative assumptions regarding economic indicators (including employment, productivity and income), demographic indicators, and certain other indicators. From these studies a range of projections is developed and a resultant most probable forecast is established, which has taken into account both local considerations and more general economic factors.

For instance, although recent trends in conservation and other customer actions tend to be reflected in the returns from the local areas and direct customers, an attempt is made to capture longer term gains in conservation, load management and improved end use efficiency predictions in the overall total aggregated forecast.

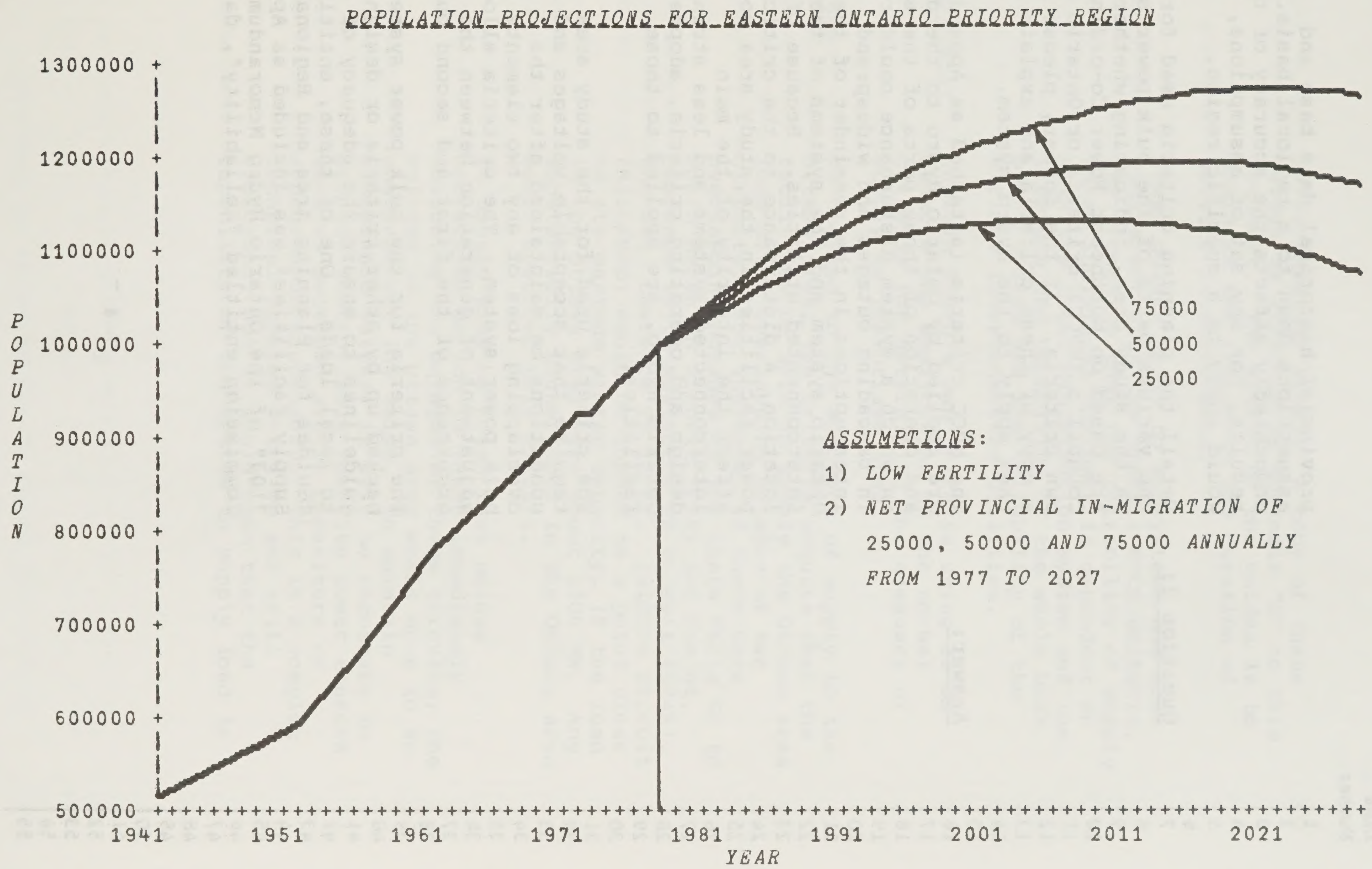
Some of the data utilized in the load forecasting process is developed within Ontario Hydro, in conjunction with other government agencies where appropriate. For the socio-economic data useful in determining overall provincial and regional trends Ontario Hydro relies mainly on information published by the provincial and federal government agencies. Examples are the annual publication of Ontario Statistics, the Annual Census of Manufacturing (derived from the Statistics Canada Survey) and population projections (prepared by TEIGA), all provided by the provincial government. Use is also made of Statistics Canada's "CANSIM" data base for historical time series disaggregation by regions and other characteristics. Additional information is also used such as the Canadata Construction File. A copy of the most recent population

projections for the study area broken down by age group, sex and county has been provided to the Commission. This was prepared by Ontario Hydro from information developed by the Ministry of Treasury, Economics and Intergovernmental Affairs based on the 1976 mid-decennial survey. The graph opposite shows the total population forecast assuming low fertility rate and varying net migration into the province.

As previously indicated, estimates of factors which are useful in an end use approach to forecasting, similar to those mentioned in the Commission's question are not developed and used in the current forecast methodology. They are, however, developed by the CEA-SRI model discussed in the submission.

The complete set of historical data and the resultant forecasts for base scenario (Scenario 1) identified in the main submission is provided in Appendix E. This includes information on population, employment, number of households, both historical and predicted, as well as the related electrical energy growth. It must be emphasized that little experience has been gained to date with this model and the three scenarios in the submission indicate the effects of changing only a single input variable, the Ontario Gross Domestic Provincial Product. Until an understanding of the limitations, strengths and weaknesses of the model have been developed, it will not be heavily relied upon in arriving at an official load forecast and the range of uncertainty associated with such forecast. It is however a useful analytic tool when comparing the effects on load growth in various energy sectors of a variety of postulated conditions.

At this stage in the development of the use of this model only limited capability has been developed to break the overall


POPULATION PROJECTIONS FOR EASTERN ONTARIO PRIORITY REGION
POPULATION
1300000
1200000
1100000
1000000
900000
800000
700000
600000
500000
1941
1951
1961
1971
1981
1991
2001
2011
2021
YEAR
75000
50000
25000
ASSUMPTIONS:
1) LOW FERTILITY
2) NET PROVINCIAL IN-MIGRATION OF
25000, 50000 AND 75000 ANNUALLY
FROM 1977 TO 2027

provincial historical data base and assumptions down to a regional basis. This undoubtedly affects the accuracy of the results, for any set of assumptions, as they would apply to a specific region.

Question 2: Detail the planning criteria used for the various parts of the bulk power system in the study area, indicating whether they are based on Northeast Power Co-ordinating Council's (NPCC) criteria or Ontario Hydro's own criteria. If the former, please provide a copy of these criteria and explain how they apply to the Hydro system.

Answer: The NPCC criteria (attached as Appendix F) are applied by Ontario Hydro to the design and operation of those parts of the system in which a system disturbance could result in cascading outages and widespread interruptions in the remainder of the Ontario system and the systems of the interconnected utilities. Because of their location, a disturbance to the critical bulk power facilities in the study area would not affect the integrity of the main interconnected systems and less stringent design and operating criteria, adopted by Ontario Hydro, are applied to those facilities.

The criteria used for the study area require that acceptable voltages and loading conditions be maintained after the overlapping loss of any two elements of the bulk power system. The criteria allow for adjustment of generation between the occurrence of the first and second outages.

The criteria for the bulk power system are backed up by other criteria or design guidelines to ensure the adequacy of supply to local loads. One of these, entitled "Guides for Planning Area and Regional Supply Facilities" was included as Appendix "10J" of the Ontario Hydro Memorandum to the Commission entitled "Reliability", dated May,

1976, (Exhibit 20-0). A copy of these guides is attached as Appendix "G" to this document. The intent of the guides is to minimize the frequency and duration of service interruptions.

These guides apply to subsystems and are consistent with the overall NPCC criteria, and recognize that the reliability of supply to an individual customer is dependent on both the local distribution system and the strength and capability of the whole bulk power system and the reliability of the various interconnected utilities.

<u>Question 3:</u> Explain Hydro's own criteria using as an example the application of the normal criteria for determining the adequacy of supply to the Ottawa area.

<u>Answer:</u> As applied to the adequacy of supply to the Ottawa area, the criteria require that the facilities be able to supply the Ottawa area load after overlapping outages of two circuits. For instance, if there were overlapping outages of the Chats Falls GS to South March TS circuit (C3S) and the St. Lawrence TS to Hawthorne TS circuit (L24A), the St. Lawrence TS to St. Isidore circuit (B31L/B5D) would be loaded to a point close to its maximum winter capacity, if the load in the Ottawa area were about 1300 MW. Any substantially higher load in the Ottawa area would overload this circuit.

It should also be noted that unless corrective action is taken immediately following the outages of these circuits, the voltage in the Ottawa area would drop to an unacceptably low value. To maintain acceptable values, it will be necessary to provide controllable reactive power sources such as switched static capacitors or synchronous condensers. This is a complex technical problem which we are still exploring, but it could mean that the capability of the system to supply load is

somewhat lower than the 1300 MW figure derived from the thermal capability of the lines.

Question 4: What value do the customers place on reliability of service?

Answer: Ontario Hydro has recently undertaken a number of surveys of customers' attitudes to reliability of supply in various customer groups. Three reports, namely those providing the response from large industrial customers, small industrial customers and farm customers, have been finalized and filed with the Commission and reports dealing with responses from commercial, institutional and residential customers are being prepared. The average value which the various classes of customers place on an interruption in their supply is shown in the figure opposite. It will be seen that the farm group placed the highest value on reliability of service, followed by small industry, large industry, retail, commercial, institutional and finally residential customers.

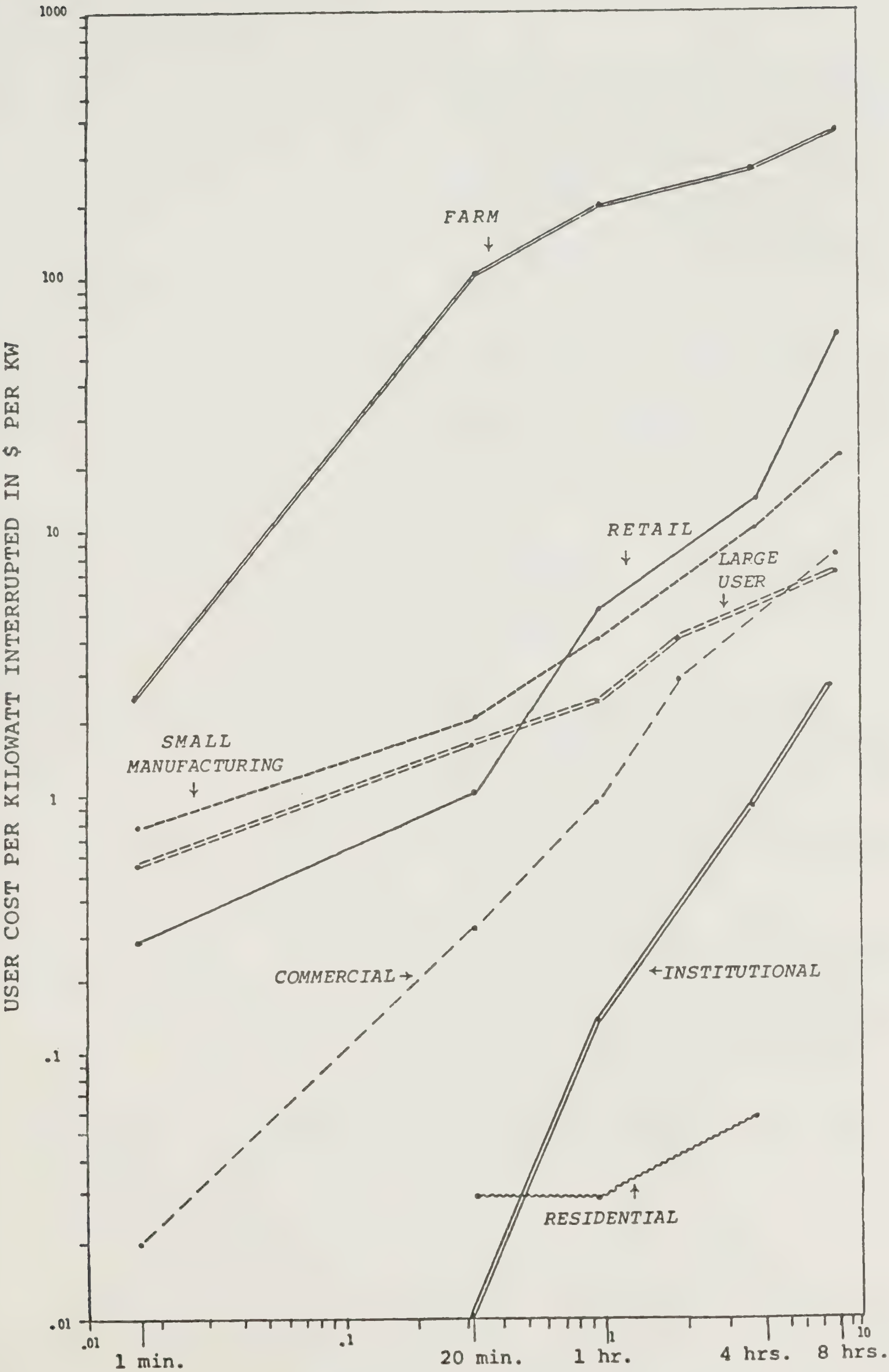
Question 5: Please explain the various classes of and provide copies of typical contracts for the supply of interruptible power to Ontario Hydro's direct customers.

Answer: In general, interruptible loads are those which can be interrupted under contract provisions in exchange for which power is sold at a rate more favourable to the customer. At present, there are three classes of interruptible power, namely:

Class "A" (Capacity) - designed to reduce the generation requirement for the system during adverse and emergency conditions such as major equipment loss, shortage of power, etc.

Normally such loads would be

USER ESTIMATES OF INTERRUPTION COSTS



DURATION OF INTERRUPTION IN HOURS (LOG SCALE)

interrupted infrequently, but to take care of adverse conditions which might occur on the average every three or four years, the industries taking this class of power have to be prepared to accept interruptions of five hours per day, Monday through Friday only, the year around to a maximum of 15% of the hours in any month.

Class "B" (Economic) - for day-to-day operating contingencies to reduce operating costs by saving thermal starts on peaking, maintaining spinning reserve, avoiding uneconomic use of water, etc., and in emergencies.

Interruptible at any time, seven days per week the year around to a maximum of 5 hours per day, but not exceeding 15% of the hours in any month.

During the months of December, January, and February all Interruptible "A" and "B" Loads may be cut beyond the 5-hour per day limit up to 14 hours per day during emergency system conditions but total time of cuts is not to exceed 15% of the hours in any month.

Class "C" (Restricted Hour) - power made available to companies prepared to reduce load on a daily schedule of restricted hours with a resulting saving to Ontario Hydro in meeting daily system peaks.

Typical contracts for classes A and B are attached as Appendix H.

Question 6: What are the "existing and committed bulk power generation facilities" and what is their role in meeting load?

Answer: The existing and committed Ontario Hydro generating facilities at the boundary of or within the study area include:

Hydraulic	Installation Date	January Capability (MW) Dependable Peak	Dependable Average	Median Peak	Median Average
R.H. Saunders	1958-59	734	582	796	642
Chenaux	1950-51	116	45	116	77
Chats Falls	1931	94	37	96	59
Barret Chute	1942				
" "Extn	1968	172	13	172	28
	1948				
" Extn	1969	166	12	167	27
Mountain Chute	1967	165	13	167	28
Arnprior	1976-77	78	6	78	13

		Nominal Capacity (MW)
High Falls	1920	2.6
Galetta	1907	.8
Merrickville	1915-19	.9
Calabogie	1917	3.
Oil-Fired Thermal		
Lennox	1975-77	2140
Oil Combustion Turbines		
Lennox	1975	5

The load characteristics set the operating conditions which must be met by the various power resources on the system. In addition to following the instantaneous changes in

demand, the generating capacity must also be capable of meeting large variations in daily loads, reducing the energy production during the nighttime hours, and increasing it rapidly in the morning as load builds up. Apart from safety, the first consideration is to operate the system reliably, and the second consideration is to do this at lowest cost.

The reliability of the existing system is dependent on the operation of generation located in diverse geographic locations, and the scheduling of generation operating reserves which must be held in readiness to replace unforeseeable failure of generating units.

Cost considerations lead to specific "stacking" or "merit" order loadings of generation. These are generally aimed at achieving least possible use of the more expensive fuels.

For example, available hydraulic energy is used first, then nuclear followed by coal and oil. (Gas is burned at the Hearn Plant in Toronto under existing contracts but it is planned to decrease gas usage). Energy produced by combustion turbine units is considerably more costly than energy produced by large units. Typical average running and operating costs per kilowatt-hour are hydraulic .1 cents, nuclear .2 cents, coal 1.5 cents, oil 2.5 cents, combustion turbines 5.0 cents.

Because of their energy production costs, the nuclear units are designed to operate as continuously as possible. Coal-fired units are operated to meet irregular loads because of much higher fuelling cost. Combustion turbine units are used primarily to provide capacity for short periods during the winter peak.

More specifically, the generation in the study area comprises only oil-fired thermal generation at Lennox and hydraulic generation. Since Lennox is an oil-fired station, energy produced there is high in cost compared to that produced at coal or nuclear stations. Therefore, as explained above, it would be used only after all available less costly sources.

The main hydraulic stations in the study area and their roles in meeting the load are:

R.H. Saunders GS, located on the St. Lawrence River near Cornwall, is primarily a base-load plant with an output dependent on the river flow.

Chats Falls GS, located on the Ottawa River about 45 km upstream from Ottawa, is an intermediate load plant. Typical daily operating patterns for it are given in answer to question 8.

Barrett Chute GS
Stewartville GS
These are located on the Madawaska River and are peaking-type plants. Typical daily operating patterns for them in this mode of operation are given in answer to question 8. These plants, when their full output is not required at the time of peak, are sometimes operated at a lower level of output throughout the heavy-load period to provide some of the system spinning reserve.

Chenaux GS, located on the Ottawa River about 80 km upstream from Ottawa, is connected to the local supply system in the Cobden Area and to the main part of the bulk power system in the Peterborough area. It, therefore, has no role in supplying load in the study area.

Mountain Chute GS, is located on the Madawaska River close to the 230 kV line from Chenaux GS to the Peterborough area. It is connected to that line and therefore, has no role in supplying load in the study

Line Number

__Question 7:__ What are "existing and committed bulk power transmission facilities" in eastern Ontario and what in detail are the "stop-gap measures" and the costs being taken to increase their capability to supply load in the area.

__Answer:__ Bulk power transmission facilities are high capacity transmission facilities. They comprise transmission lines and associated switching and transformation equipment. They are used to interconnect major generating facilities and load centres. Such an interconnected or integrated system permits generation at diverse locations to be used to supply the main load centres, thus increasing reliability of supply, and allowing use of the lowest cost generation available on the system. In different parts of the province, bulk power transmission facilities may operate at voltages of 500,000 volts (500 kV), 230 kV or 115 kV.

Near the load centers, electricity is taken from the bulk power transmission network and stepped down through transformers to lower voltages for transmission to locations closer to the loads. Voltages may range from 230 kV to 27.6 kV.

At the load centres, electricity is stepped down through transformers to lower voltages, for distribution to locations adjacent to ultimate customers. At these locations the voltage is stepped down further to deliver electricity to customers at the voltages they use. Small customers take electricity at 115 volts or 230 volts, but large customers take electricity at higher voltages.

In eastern Ontario, 115 kV and 230 kV are used as the bulk power transmission voltages. Figures 14 and 15 of the main submission show the location of the major load supply stations, generating stations,

and bulk power transmission lines in eastern Ontario. Many of these facilities have been in service for many years and were built to transmit power from hydraulic generation in Quebec to Toronto and southwestern Ontario. With the expiration of the Quebec contracts and the rapid growth of load in eastern Ontario, these lines now transmit power from Toronto and Lennox to eastern Ontario. Some of these circuits would have become overloaded shortly. However, an extensive program of measures to uprate them is now under way in order to provide a reasonable level of service security until new bulk power facilities can be installed.
Such stop-gap measures to uprate transmission lines require some combination of the following:

- restringing a line with heavier conductors
- raising towers by adding extensions
- replacing angle and anchor towers with stronger towers on new foundations

The stop-gap measures at major transformer and switching stations include replacing or uprating current carrying parts of station equipment such as circuit breakers and line disconnects.

About half the stop-gap work required for line and station uprating has been completed and most of the remainder is scheduled to be finished this year and next. Figures 15 and 16 of the main submission indicate the capacities of the affected circuits before and after the stop-gap work respectively.

In addition to the uprating work at the stations, large banks of static capacitors or other types of reactive power sources are required to ensure acceptable system voltages required at the heavier loadings of the transmission system. If the capacitors were left in service at times when lines are lightly loaded (eg. at night), the system

Line Number

voltages would be too high. Therefore, it is necessary to switch the capacitors on and off to match the loading on the transmission lines. If a transmission circuit is faulted and switched out of service, then the loadings on the lines remaining in service are increased. If blackouts are to be avoided, the static capacitors must be switched on immediately by automatic controls. The automatic control schemes must be carefully designed to function correctly under all system conditions.

The stop-gap measures are complex, requiring many thousands of hours of engineering study and design. The work is still being done, and final estimates of the cost of the facilities are not yet available. However, preliminary estimates indicate that the total cost will be about $40,000,000. It is expected that the stop-gap measures will have limited value after the major bulk power facilities are placed in service.

A detailed list of the stop-gap work is attached as Appendix I.

Question 8: Provide approximate hour-by-hour generating patterns for a weekday and weekend in January 1987 for the four Hydro plants shown on P.11 Eastern Ontario report considering:

a) no transmission restrictions

b) transmission restrictions if no additional facilities are constructed.

Provide estimates of the cost of such changes in operations, i.e., state (a) to state (b), on a total system basis.

Answer: (a) If there were no transmission restrictions, the Barrett Chute, Stewartville and Arnprior stations would probably be operated at less than full load at time of peak and day-time heavy load. They would in that way

provide part of the system spinning reserve. Typical patterns are shown for them and for Chats Falls on the opposite page.

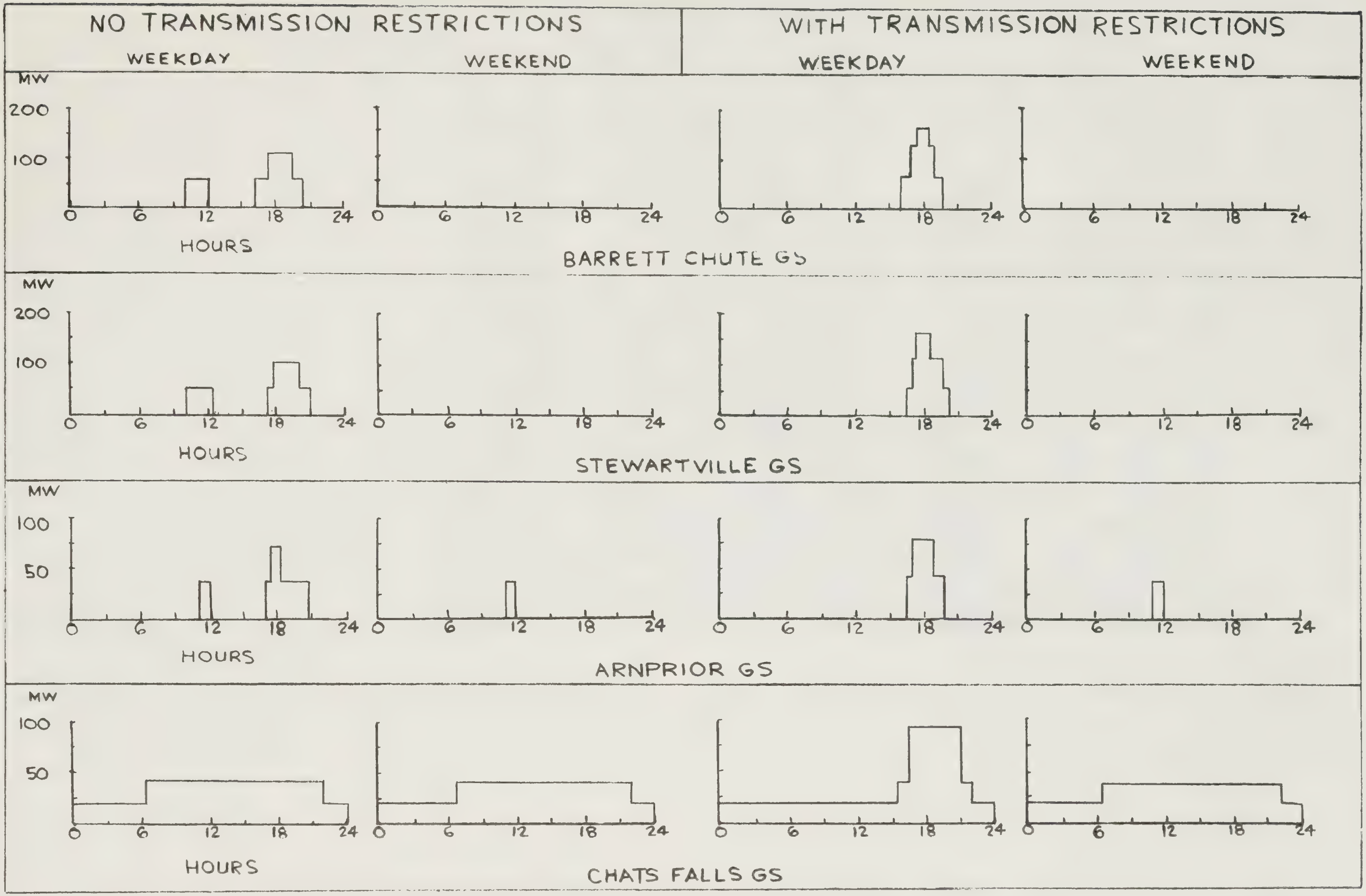
(b) The transmission system capability to supply the Ottawa-area load if no additional facilities are constructed, is dependent on the Barrett Chute, Stewartville, and Arnprior generating stations being at peak output. Therefore, when the Ottawa-area peak load is at or near the transmission system limit, these three stations will be operated in the peaking mode. Patterns for this mode of operation are also shown on the opposite page.

The cost difference between the two modes of operation is due to the need to provide the spinning reserve on thermal units elsewhere in the system. This cost difference depends on such factors as load patterns, daily load peak, unit start-up costs and unit availability . Over the period of a year the cost difference will be in the tens of thousands of dollars range.

<u>Question 9</u>: Explain what is meant by "voltage collapse".

<u>Answer:</u> Voltage collapse means the decline in voltage, after an initiating disturbance, that continues until some other action takes place. This action may be reduction of load by motor controllers dropping out, disconnection of blocks of load either automatically or by operator control to avoid damage to equipment, or cascade tripping of supply lines due to line protections. The latter could result in a blackout of the entire area.

<u>Question 10:</u> How are the capability of existing and committed bulk power facilities and the use of interconnections with neighbouring utilities related?



HOURLY OUTPUT OF SELECTED HYDRAULIC PLANTS IN EASTERN ONTARIO STUDY AREA

Line Number

Answer: There is no ability to use the interconnections in eastern Ontario for export when the existing and committed bulk power facilities are operating at their maximum capability to supply Ottawa-area load. This is an undesirable situation since the intent of interconnected operation is that neighbouring utilities be able to assist each other as required.

Import of power from New York State would not affect the capability to supply the Ottawa area because of transmission limitations between St. Lawrence TS and Ottawa.

Import of power from Hydro-Quebec would only affect the capability to supply Ottawa-area load if it were available on a firm basis. The extent to which firm power from Hydro-Quebec could be used to supply the Ottawa area would depend on the point of delivery. Hydro-Quebec has advised that no firm power will be available until 1985. After 1985, the availability and cost of firm power from Hydro-Quebec is unknown. In view of this uncertainty, it is prudent to base the supply of the Ottawa area solely on Ontario sources.

Therefore, the capability of the existing and committed bulk power facilities was determined with zero loading on the interconnections with Hydro-Quebec and New York State.

APPENDIX A

Potential Long Term Growth of Demand in the East System

During 1978, real output in the Canadian economy is estimated to have increased by about 3.4% to $126,700 million expressed in dollars of 1971 purchasing power. This amounts to some $12,565 per employed person, a token change of 0.74%, from 1977, with employment having increased by 2.63%. Ontario employment increased about 3.3%, also leaving little room for increase in output per employee or gross productivity as it is sometimes called.

Prior to 1973, output per person employed in the Canadian economy increased on average at a fairly steady rate of 2¼% per annum in the postwar period with minor variations during booms and recessions. However, since 1973, this measure of economic health has grown at only 0.5% per annum on average. It is the problem area of Canadian economic policy.

The employment record, on the other hand has been quite different. During the period 1952-64, this grew at a mean rate of 2¼% per annum, suggesting a mean rate of economic growth of 4½% per year. Growth of the labour force reflected the opposing effects of low birth rates during depression and war and offsetting this, a high immigration rate.

By 1964, birth rates had started to fall dramatically, and women started to enter the labour force in large numbers. At the same time, the first of the bumper crop of postwar babies also became old enough to work.

In its first annual review, the Economic Council of Canada estimated the potential growth rate of the Canadian economy at 5½%. At the trend rate of growth in output per employee, this required employment to grow by 3.17%. In Ontario, the average rate of employment growth 1964-1978 was 3.12%, with some falling off during the period 1975 through 1977, so that the growth between 1974 and 1978 was an equivalent 2¼% compounded annually.

Prospects for Economic Growth

(i) Employment:

The impact of the declining birth rates had hit the educational system, the housing market, and is now beginning to affect universities and the labour force. The prospects are therefore for labour

force growth from this source to contract sharply during the coming five years. One aspect of this may be favourable inasmuch as unemployment rates tend to be much higher for younger members of the labour force, and so total unemployment may decline if there is no further deterioration in the rate of growth of total output. Perhaps more importantly, the non-inflationary full employment rate may also fall somewhat.

The other source of native entries to the labour force is women. Their participation rate is currently about 59%, and may continue to rise somewhat, albeit from a smaller base for young women discussed above.

The prospects for immigration are more difficult to forecast, especially for Ontario as net migration is also involved. In the past this has depended not only upon economic conditions and therefore the demand for labour in Ontario, but also upon relative prospects in the place of origin (or destination). The prospects also depend upon government policy.

(ii) Output per Employee:

Output per employee was about 7.3% below the long term trend of 2.26% in 1978. This gap is undoubtedly related to the lack of growth of investment in the Canadian Economy since 1975 and to low rates of capacity utilization. The ability to pass on cost increases in a period of inflation has made it possible for businessmen and governments to keep unproductive labour on the payroll. This in turn may have aggravated inflation and eroded the international competitiveness of Canada which has resulted in a significant devaluation of the Canadian dollar. It may not have been the ideal way of coping with one of the fastest growing populations of working age in the world, but it is superior to some of the alternatives.

From a forecasting point of view, the present situation poses two questions:

(a) Will the lost ground of 7.3% be made up?

(b) Will the growth rate resume?

The first question is one of levels of output, and really reduces to whether the lost ground can be recovered. The historical record

suggests that it can be if investment recovers and if capacity utilization rates rise. At the present time, an enterprise wishing to expand its operations can probably do so more cheaply by way of merger or acquisition than by new investment, so long as capacity utilization rates are low. There are signs that business investment in real terms will rise 5% or so in 1979. Investment in housing appears to have peaked in 1973, probably reflecting the demographic features referred to above. On the other hand, the decline in the Canadian dollar appears to have restored Canada's international competitive position and this may lead to a resumption of investment in export industries, accompanied by a secular decline in housing investment. The prospect of increasing levels of investment coupled with a decline in the growth rate of the labour force suggests both a decline in unemployment and an increase in output per employee. However, insofar as the initial impetus for such a move depends upon the external environment, it may be delayed for a year or two.

One purpose of the expansion of higher education and the creation of a health scheme in Canada was to enhance the productivity of the labour force.

Potential Growth in Total Output

Translated into economic growth potential, the implications are as follows:

	% per Annum		
	Employment	Output/Employee	Total Output
1980-85	1.95 (2.5)*	2.26 (3.6)**	4.25 (4.81)* (5.6)** (6.1)***
1985-90	1.4	"	3.7
1990-95	1.0	"	3.3
1995-00	.8	"	3.1

* Includes 3% decline in unemployment.

** With recovery 7.3%.

*** The 6.1% growth to 1985 represents a change in level resulting from making up the output/employee gap of 7.3% and reducing unemployment by 3%.

It has been argued that there may be a secular decline in productivity growth on grounds that the Canadian economy is evolving into a "POST-INDUSTRIAL" society. This means that the economy is tending to become more service producing and less goods producing. It is thought that productivity gains are more

difficult to realize in service industries. This would imply a logistic trend in output per employee resulting in the following:

	% per Annum		
	Employment	Output/Employee	Total
1980-85	1.95	1.8	3.8
1985-90	1.4	1.5	2.9
1990-95	1.0	1.3	2.3
1995-00	.8	1.1	1.9

Quantitative Assessment of Factors Affecting East System Demands

An econometric study has suggested that the East System December peak demands for the period 1957-78 can be reasonably explained as follows:

Variable (Logarithm)	Elasticity (short run)	't'	Elasticity (long run)
Constant	-10.41	-6.0	
Real output/employee	1.12	7.2	1.34
Employment	1.45	12.7	1.26
Demand Price	-.412	-10.2	-.465
Energy Price	-.127	-4.8	-.167
Oil Price	-.129	-2.5	-.10
Gas Price	-.043	-3.9	-.041
Temperature*	-.00013	.6	N.A.

* Degrees farenheit at 5 p.m. (not logarithm)
Electricity and gas prices lagged one year

The model specification assumes that elasticities are constant.

Effects of the Economy

The average of the elasticities for output/employee and employment is 1.28 in the short run and 1.30 in the long run can be taken to represent the response to real output. The closeness of the two suggests that the effects tend to be felt almost immediately. A long term elasticity of 1.3 implies roughly an increase of 1.3% for a 1% increase in output. Thus the previous estimates of potential economic growth can be translated into load growth:

Potential Growth

	Output of the Economy			Load		
	Low	Probable	High	Low	Expected	High
1980-85	3.8	4.25	(6.1)	4.9	5.6	8.0
1985-90	2.9	3.7		3.8	4.8	
1990-95	2.3	3.3		3.0	4.3	
1995-00	1.9	3.1		2.5	4.0	

The estimate of load growth selected by the Royal Commission on Electric Power Planning of 4% for the period to 2000 is thus consistent with economic growth of 3.06%, with all else held constant.

Effect of Electricity Prices

While the model estimates peak and energy charges separately, the elasticities are additive for the combined effect of -.539 in the short run and -.632 in the long run. Applying these to the estimated rates of price change in Long Range Financial Projection 781201 yields the following estimates:

	Price Change	Effect on Load	Potential Load Growth Low	Expected	High
1980-85	2.40	-1.49	3.3	4.0	6.4
1985-90	-1.07	.68	4.5	5.5	
1990-95	-.65	.41	3.4	4.7	
1995.00	-.51	.32	2.8	4.3	
1980-2000 Avg.	0	0	3.5%	4.6%	5.2%

Effect of Prices of Oil and Gas

It is perhaps significant that the estimated long term elasticities in the model for oil and gas are lower than the short run estimates. It is also worthy of note that the signs for these fuels are negative, suggesting that they complement electricity in the short run rather than act as substitutes. In the short run, they may very well complement one another.

Oil heated houses tend to heat water electrically and gas heated houses generally have electric circulating fans or pumps. In another sense, falling prices for oil and gas may have stimulated the Ontario economy, with subsequent price increases serving to retard it, with the demand for electricity moving in sympathy.

In the long run, however,,one would expect to see substitution, especially if the price of oil and gas moves upward while the price of electricity is declining. The model cannot capture this effect, but it suggests it insofar as the long run estimates of elasticity are closer to zero than the short run estimates. It therefore suggests that the impact of another oil supply crisis might be initial depression and subsequent expansion in the demand for electricity. It also suggests that orderly price increases in oil and gas may stimulate the demand for electricity in the long run. But it is not possible to provide a quantitative estimate.

A qualitative set of assumptions therefore becomes necessary.

1980-85 Continued adjustment to the 1973 price step with no net effect of substitution on the demand for electricity.
However, the period does contain elements of cyclical recovery from the depressed levels of output/employee, assumed to amount to about 1% and reflected in the short term forecast.

1985-90 Possible emergence of Mid East Supply difficulties with appreciable escalation in the price of oil, and possibly of electricity resulting in a net short term reduction in the demand for electricity estimated at 0.6%.

1990-95 Net substitution effect reduces shifts to -.2% as the gap between electricity prices and those for oil and gas widens. Some possibility of solar energy competition.

1995-00 Net substitution shifts to -.3% with increased solar energy participation.

The net effect of these changes on potential load growth becomes:

Potential Load Growth

	Previously Estimated (Expected)	Cyclical Effect	Substitution Effect	Total
1980-85	4.0	+1.0	0.0	5.0
1985-90	5.5	-	-0.6	4.9
1990-95	4.7	-	-0.2	4.5
1995-00	4.3	-	-.3	4.0

The totals above are recommended for the 1979 load forecast.

Risks

Elements of risk associated with the forecast can be classified as follows:

(1) Modelling risk. The responses of the model to changing conditions may result in an overestimate or an underestimate of demand.

(2) The forecasts of output/employee and of employment may be high or low.

The estimate derived from the model assumption of full employment and a restoration of output/employee to trend levels by 1985 could result in a demand 15% higher than the forecast, assuming no price change, 7% with the price changes as assumed.

Similarly, the estimate based on existing unemployment levels and modest growth in output/employee indicates 1985 demand 7.6% less than forecast. The shortfall could be more severe if low demands resulted in even higher prices.

(3) The long range forecast is subject to even larger risk of error.

Conservation

It is assumed that conservation activities are fully captured in the response to price used in these calculations. That is to say, the price elasticity is a best estimate, and it is assumed that consumers will adjust their demand and lifestyles to incorporate an optimum amount of conservation.

Impact of Alternative Rate Structures

Alternative rate structures such as time of day or temperature sensitive rates may alter both the pattern and magnitude of energy consumption over the day, over the year, and over the business cycle. In particular, an industrial customer facing a soft market may be willing to cancel the daytime shift and flatten the system load curve, given a sufficient price incentive. However, when business picks up, the customer faces the choice of adding capacity for night-time use or of extending into the peak hours with his existing plant, at a time when there is likely to be more pressure on the utility capacity. The attached forecast is based on present rate structure.

Impact of Load Management

Load management in its broad definition is the result of actions by Ontario Hydro to alter the pattern and level of demand by any means, including marketing to do so. In its narrow definition, load management is a means of altering demand for limited periods at the initiative of Ontario Hydro as operating conditions may dictate, and as such is a substitute for capacity as for example interruptible load. This forecast is of primary demand, which assumes that interruptible and managed loads are being supplied.

It is adjusted for planning purposes to allow for reductions estimated to be available due to contractual interruption and load management.

Utilization Forecasting
Power System Program Branch
February 5, 1979

LOAD FORECAST REPORT 790212

ONTARIO PRIMARY PEAK DEMANDS - MW

Winter	East System Dec.	East System Jan.	West System Dec.	West System Jan.	Total System Dec.	Total System Jan.
1979/80	15760	16280	869	877	16629	17157
1980/81	16233	16769	899	877	17132	17646
1981/82	16882	17439	896	907	17778	18346
1982/83	17769	18355	930	942	18699	19297
1983/84	18701	19318	974	986	19675	20304
1984/85	19683	20333	1009	1021	20692	21354
1985/86	20667	21349	1049	1063	21716	22412
1986/87	21701	22417	1091	1106	22792	23523
1987/88	22786	23538	1135	1150	23921	24688
1988/89	23925	24715	1180	1196	25105	25911
1989/90	25121	25950	1228	1243	26349	27193
1990/91	26252	27118	1277	1293	27529	28411
1991/92	27433	28388	1328	1345	28761	29683
1992/93	28668	29614	1381	1399	30049	31013
1993/94	29958	30947	1436	1455	31394	32402
1994/95	31306	32339	1493	1513	32799	33852
1995/96	32715	33795	1553	1573	34268	35368
1996/97	34024	35147	1615	1636	35639	36783
1997/98	35385	36553	1680	1702	37065	38255
1998/99	36800	38015	1747	1770	38547	39785
1999/00	38272	39536	1817	1840	40089	41376
2000/01	39803	41117	1890	1914	41693	43031
2001/02	41395	42762	1965	1990	43360	44752
2002/03	43051	44472	2044	2070	45095	46542
2003/04	44773	46251	2126	2153	46899	48404
2004/05	46564	48101	2211	2239	48775	50340
2005/06	48427	50025	2299	2328	50726	52353

The 1979 Medium Term Forecast

East System

The 1978 Forecast:

In the fourth quarter of 1977, demands dropped below those of the previous year because:

(1) Economic growth continued well below potential, in contrast to most previous post-war business cycles which have lasted on average for three years.

(2) Increases in the real price of electricity (after allowing for inflation) began to have an impact upon demand.

(3) Ontario Hydro's conservation program entered the implementation phase.

The regional forecasts were made before the fourth quarter results were known. A correction in the form of unallocated load was made to the regional estimates, on the assumption that the major impact of the conservation program would be in the cold dark months. While this assumption appears to have been partly valid, in that November peak demand was above forecast, summer demands were significantly lower, and both December and January peak demands exhibited no growth for the third consecutive year.

The 1979 Regional Estimates:

The new regional estimates for the 1979 forecast are below those of last year, but for 1979, they are slightly above the 1978 forecast, although they are lower thereafter, reflecting a lower expected growth rate.

An alternative forecast was provided by a mathematical model which incorporates the Ontario Hydro's economic forecast and the outlook for electricity prices. The alternative forecast was significantly lower than the regional estimates, suggesting that the regional estimates should be reduced, but the amount depends upon the exercise of judgment.

The two forecasts and the exercise of judgment is depicted in the following table:

December	Regional Estimates	% Inc	Model	% Inc	Forecast 7901P	% Inc	Unallocated Load
1978	14,940(Act)		15,300*				
1979	16,525	8.0	15,543	1.6	15,760	3.0	-765
1980	17,342	4.9	15,023	-2.7	16,233	3.0	-1109
1981	18,338	5.7	15,234	1.3	16,882	4.0	-1456
1982	19,168	4.5	16,081	5.6	17,769	5.25	-1399
1983	20,059	4.6	17,056	6.1	18,701	5.25	-1358
1984	20,988	4.6	18,278	7.2	19,683	5.25	-1305

* Adjusted for Inco Strike and Weather

The exercise of judgment was conditioned by the following factors:

(1) The starting point of the regional estimates appears to be too high as indicated by a forecast growth of 8% in 1979.

(2) The high rates of growth indicated by the model in 1982-1984 depends critically upon the timing and magnitude of an increase in economic activity. There is considerable uncertainty about both timing and magnitude.

(3) The very low rates of growth shown by the model reflect large real price increases and a very weak economy.

(4) A similar model for January demands reveals considerably less discrepancy under identical assumptions about the external and pricing environment.

The forecast is therefore a weighted judgment of these factors. The necessity to make such a judgment in the first instance is an indication of increased uncertainty. The forecast 7901P in January terms compared to the model results is as follows:

January	7901P	% Inc	Model	% Inc
1980	16,280	4.0	16,241	3.7
1981	16,769	3.0	16,462	1.4
1982	17,439	4.0	17,431	5.9
1983	18,355	5.25	18,503	6.1
1984	19,318	5.25	19,862	7.3
1985	20,333	5.25	21.406	7.8

The forecasts for 1983 to 1985 are lower than the results indicated by the model, but this reflects the smoothing assumption made about the course of the economy. The Ontario Hydro's economic forecast indicates deteriorating conditions after 1985.

West System

The principal changes in the forecast for the West System are two in number:

(1) Reduction in the estimate of system demands to reflect sharply lower losses that were experienced commencing in the fall of 1977. This change does not affect customer demands which are the losses of revenue estimates.

(2) Advancement to 1979 from 1980 of the closedown of a mining operation in the Atikokan area.

Utilization Forecasting
Power System Program Branch
February 5, 1979

COMPARISON OF WINTER PEAK DEMAND WITH EARLIER FORECASTS
EAST SYSTEM - ONTARIO PRIMARY DEMAND
Megawatts

		FORECAST MADE IN						
Winter	Actual	1973	1974	1975	1976	1977	1978	1979
1973/74	12858	12909						
1974/75	13214	13926	13720					
1975/76	14266	15026	14850	14160				
1976/77	15164	16063	16128	15392	14857			
1977/78	15420	17177	17438	16675	16089	15869		
1978/79	15580*(P)	18365	18830	18079	17391	17031	15880	
1979/80		19650	20152	19318	18578	18126	16627	16280
1980/81		21026	21563	20598	19831	19365	17735	16769
1981/82		22497	23072	22019	21143	20664	18723	17439
1982/83		24072	24687	23538	22578	21999	19750	18355
1983/84		25757	26415	25163	24113	23385	20833	19318
1984/85		27560	28264	26899	25753	24860	21979	20333
1985/86		29489	30243	28809	27505	26453	23188	21349
1986/87		31553	32360	30854	29374	28170	24463	22417
1987/88		33762	34625	33045	31372	29979	25808	23538
1988/89		36125	37049	35391	33506	31896	27214	24715

WEST SYSTEM - ONTARIO PRIMARY DEMAND

Winter	Actual	1973	1974	1975	1976	1977	1978	1979
1973/74	754	770						
1974/75	736	785	788					
1975/76	752*	834	838	812				
1976/77	862	877	892	873	828			
1977/78	847	927	953	950	922	904		
1978/99	791(P)	975	1014	1005	1010	930	916	
1979/80		1023	1083	1066	1066	1008	901	877
1980/81		1074	1140	1132	1134	1073	935	877
1981/82		1128	1199	1191	1195	1110	959	907
1982/83		1184	1261	1253	1257	1175	1006	942
1983/84		1243	1327	1319	1323	1234	1058	986
1984/85		1306	1396	1387	1391	1296	1105	1021
1985/86		1370	1469	1459	1464	1360	1155	1063
1986/87		1439	1545	1535	1540	1428	1207	1106
1987/88		1511	1625	1615	1620	1500	1261	1150
1988/89		1587	1710	1699	1704	1575	1318	1196

* Adjusted for Strikes
(P) Preliminary

REPORT NO. 790212

TOTAL SYSTEM

CUSTOMERS LOADS AND DEMANDS

	MUNICIPAL		RETAIL		DIRECT	
	PEAK MW	ENERGY AV MW	PEAK MW	ENERGY AV MW	PEAK MW	ENERGY AV MW
1979						
JAN	11097	8212	3145	2156	2283	1801
FEB	10478	7918	2992	2032	2279	1844
MAR	9862	7373	2723	1796	2443	1883
APR	9576	6903	2438	1533	2463	1955
MAY	9226	6423	2259	1382	2451	1914
JUNE	9495	6604	1971	1239	2461	1971
JULY	9448	6514	1989	1228	2445	1800
AUG	9404	6496	2042	1308	2460	1889
SEPT	9425	6589	2162	1310	2527	1978
OCT	9320	6751	2488	1509	2568	2071
NOV	10350	7360	2851	1786	2574	2088
DEC	10881	7796	3234	2145	2577	2037
1980						
JAN	11227	8356	3342	2290	2606	2067
FEB	10581	8051	3175	2157	2612	2123
MAR	9962	7497	2893	1909	2621	2101
APR	9669	7009	2592	1630	2642	2098
MAY	9311	6517	2396	1460	2630	2055
JUNE	9607	6713	2084	1310	2636	2107
JULY	9542	6605	2126	1306	2607	1934
AUG	9510	6598	2171	1390	2626	2019
SEPT	9559	6707	2303	1395	2659	2088
OCT	9477	6889	2633	1596	2698	2182
NOV	10487	7491	3043	1905	2723	2213
DEC	11015	7937	3454	2290	2729	2160
1981						
JAN DEC	11190	8097	3734	2471	2919	2279
DECEMBER						
1982	11713	8467	3997	2644	3057	2388
1983	12275	8863	4274	2627	3198	2491
1984	12897	9299	4572	3023	3297	2571

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TOTAL SYSTEM

CUSTOMERS LOADS AND DEMANDS

	SUM CUSTOMERS LOADS		DIVERSITY AND/OR LOSSES		DEMAND IN TERMS OF GENERATION		LOAD FACTOR
1979	PEAK MW	ENERGY AV MW	PEAK MW	ENERGY AV MW	PEAK MW	ENERGY AV MW	%
JAN	16525	12168	-17	678	16508	12846	77.8
FEB	15749	11794	-82	613	15667	12407	79.2
MAR	15028	11052	-160	553	14868	11605	78.1
APR	14477	10392	-162	520	14315	10912	76.2
MAY	13936	9719	-631	631	13305	10350	77.8
JUNE	13927	9814	-321	555	13606	10369	76.2
JULY	13882	9542	-362	584	13520	10126	74.9
AUG	13906	9692	-363	540	13543	10232	75.6
SEPT	14114	9877	-580	494	13534	10371	76.6
OCT	14384	10331	-484	516	13900	10847	78.0
NOV	15775	11234	46	560	15821	11794	74.5
DEC	16693	11980	-64	633	16629	12613	75.8
1980							
JAN	17175	12714	-18	707	17157	13421	78.2
FEB	16368	12331	-82	640	16286	12971	79.6
MAR	15476	11507	-163	576	15313	12083	78.9
APR	14903	10737	-167	537	14736	11274	76.5
MAY	14337	10037	-647	653	13690	10690	78.1
JUNE	14327	10130	-332	572	13995	10702	76.5
JULY	14274	9844	-370	603	13904	10447	75.1
AUG	14308	10008	-373	557	13935	10565	75.8
SEPT	14522	10190	-595	509	13927	10699	76.8
OCT	14808	10667	-498	535	14310	11202	78.3
NOV	16253	11609	47	581	16300	12190	74.8
DEC	17198	12386	-66	654	17132	13040	76.1
1981							
JAN					17646	13815	78.3
DEC	17843	12848	-65	682	17778	13530	76.1
DECEMBER 1982	18766	13498	-67	713	18699	14211	76.0
1983	19747	14180	-72	750	19675	14930	75.9
1984	20766	14894	-74	786	20692	15680	75.8
1985					21716	16455	75.8
1986					22792	17269	75.8
1987					23921	18122	75.8
1988					25105	19019	75.8

REPORT NO. 790212

EAST SYSTEM

CUSTOMERS LOADS AND DEMANDS

	SUM CUSTOMERS LOADS		DIVERSITY AND/OR LOSSES		DEMAND IN TERMS OF GENERATION		LOAD FACTOR
1979	PEAK MW	ENERGY AV MW	PEAK MW	ENERGY AV MW	PEAK MW	ENERGY AV MW	%
JAN	15627	11458	32	642	15659	12100	77.3
FEB	14867	11094	-33	577	14834	11671	78.7
MAR	14180	10372	-113	519	14067	10891	77.4
APR	13650	9735	-117	487	13533	10222	75.5
MAY	13125	9075	-586	599	12539	9674	77.2
JUNE	13123	9168	-277	523	12846	9691	75.4
JULY	13096	8934	-319	554	12777	9488	74.3
AUG	13114	9057	-319	507	12795	9564	74.7
SEPT	13300	9256	-535	463	12765	9719	76.1
OCT	13548	9665	-439	483	13109	10148	77.4
NOV	14881	10526	95	526	14976	11052	73.8
DEC	15772	11256	-12	597	15760	11853	75.2
1980							
JAN	16246	11978	34	671	16280	12649	77.7
FEB	15461	11611	-32	604	15429	12215	79.2
MAR	14611	10814	-115	541	14496	11355	78.3
APR	14063	10071	-120	504	13943	10575	75.8
MAY	13515	9386	-602	619	12913	10005	77.5
JUNE	13522	9482	-288	540	13234	10022	75.7
JULY	13485	9233	-327	572	13158	9805	74.5
AUG	13512	9369	-328	525	13184	9894	75.0
SEPT	13704	9566	-550	478	13154	10044	76.4
OCT	13946	9977	-451	499	13495	10476	77.6
NOV	15330	10876	98	544	15428	11420	74.0
DEC	16246	11638	-13	616	16233	12254	75.5
1981							
JAN					16769	13046	77.8
DEC	16895	12104	-13	645	16882	12749	75.5
DECEMBER							
1982	17782	12726	-13	674	17769	13400	75.4
1983	18715	13370	-14	710	18701	14080	75.3
1984	19698	14056	-15	744	19683	14800	75.2
1985					20667	15540	75.2
1986					21701	16317	75.2
1987					22786	17133	75.2
1988					23925	17989	75.2

REPORT NO. 790212

WEST SYSTEM

CUSTOMERS LOADS AND DEMANDS

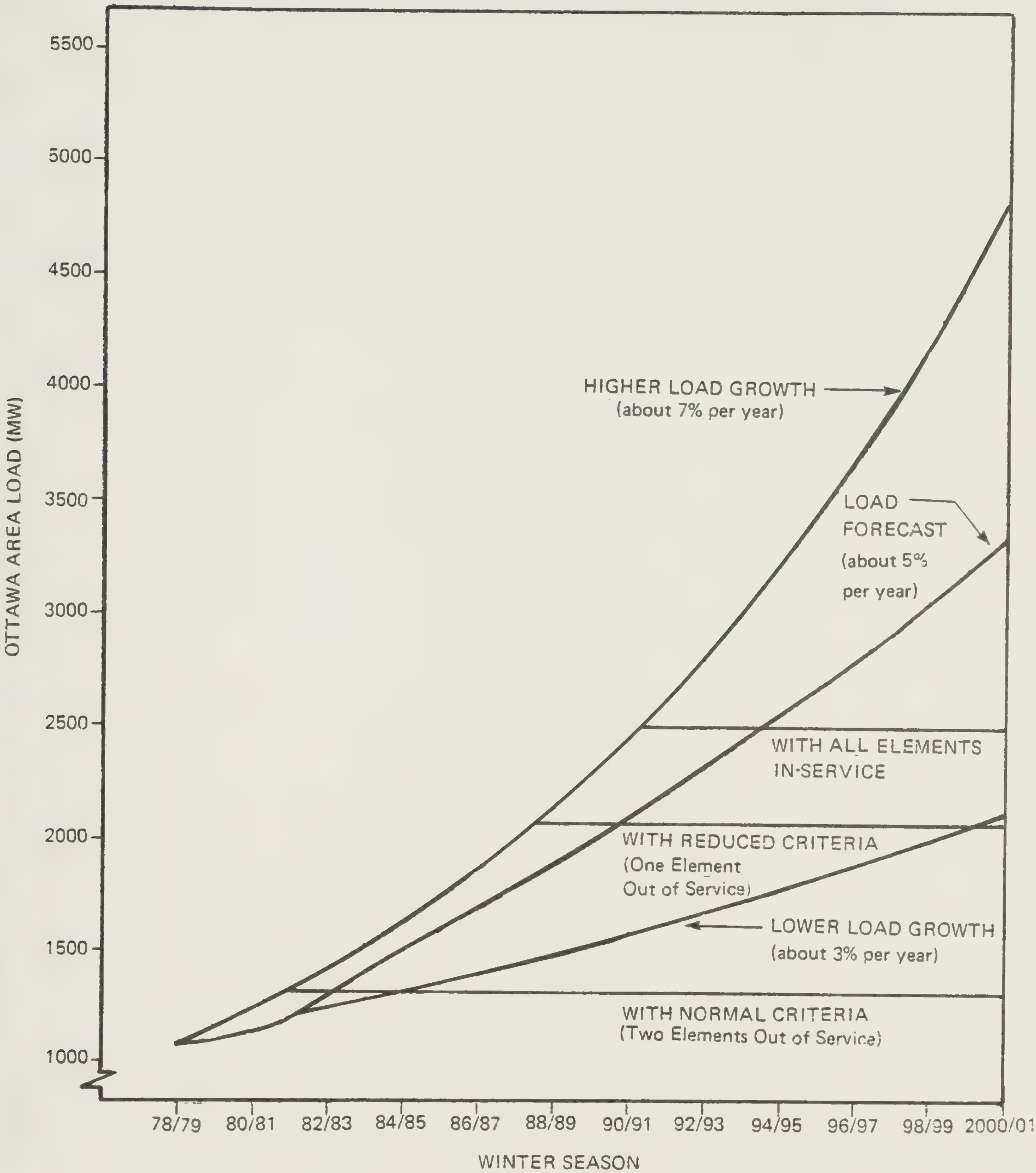
	SUM CUSTOMERS LOADS		DIVERSITY AND/OR LOSSES		DEMAND IN TERMS OF GENERATION		LOAD FACTOR
1979	PEAK MW	ENERGY AV MW	PEAK MW	ENERGY AV MW	PEAK MW	ENERGY AV MW	%
JAN	898	710	-49	36	849	746	87.9
FEB	882	701	-49	35	833	736	88.4
MAR	848	680	-47	34	801	714	89.1
APR	827	657	-45	33	782	690	88.2
MAY	811	644	-45	32	766	676	88.3
JUNE	804	646	-44	32	760	678	89.2
JULY	786	608	-43	30	743	638	85.9
AUG	792	636	-44	32	748	668	89.3
SEPT	814	621	-45	31	769	652	84.8
OCT	837	666	-46	33	791	699	88.4
NOV	894	707	-49	35	845	742	87.8
DEC	920	724	-51	36	869	760	87.5
1980							
JAN	929	735	-52	37	877	772	88.0
FEB	907	720	-50	36	857	756	88.2
MAR	865	693	-48	35	817	728	89.1
APR	840	666	-47	33	793	699	88.1
MAY	822	652	-45	33	777	685	88.2
JUNE	805	648	-44	32	761	680	89.4
JULY	789	611	-43	31	746	642	86.1
AUG	795	639	-44	32	751	671	89.3
SEPT	818	624	-45	31	773	655	84.7
OCT	862	691	-47	35	815	726	89.1
NOV	923	732	-51	38	872	770	88.3
DEC	951	749	-52	37	899	786	87.4
1981							
JAN					877	769	87.7
DEC	948	744	-52	37	896	781	87.2
DECEMBER							
1982	984	772	-54	39	930	811	87.2
1983	1031	810	-57	40	974	850	87.3
1984	1068	838	-59	42	1009	880	87.2
1985					1049	915	87.2
1986					1091	952	87.3
1987					1135	989	87.1
1988					1180	1030	87.3

APPENDIX B

FORECAST OF OTTAWA AREA STATION LOADS
COINCIDENT WITH JANUARY PEAK

Station	Load (MW) 1981	1986	1991	1996	2001
Hawkesbury Area	79.9	152.2	208.9	261.7	312.2
South March	90.5	79.5	109.8	157.9	218.9
"Almonte"	-	56.0	79.9	105.0	134.0
Hawthorne	103.2	116.9	177.6	242.9	310.9
St. Isidore	54.2	76.8	108.9	144.6	182.3
Ottawa-Albion	72.3	95.0	120.5	153.7	194.1
Ottawa-Russell	34.4	49.0	61.2	76.9	96.3
Ottawa	67.7	83.1	103.8	130.4	163.5
Stewartville	14.6	10.4	14.5	17.9	17.9
Ottawa (NRC)	7.0	7.1	7.2	7.2	7.3
Ottawa-Woodroffe	25.1	31.2	38.9	48.9	61.3
"Goulbourn"	-	24.1	51.6	60.4	69.8
Ottawa Riverdale	40.8	57.1	71.4	89.7	112.4
Navan	6.2	7.6	8.5	8.5	8.5
Richmond	2.8	2.2	3.2	3.7	3.8
Ottawa-Overbrooke	64.7	46.8	58.4	73.4	91.9
Cassburn	5.7	4.8	6.7	7.1	7.1
Hazeldean	7.9	8.0	8.0	8.0	8.0
Uplands	5.4	5.4	5.4	5.4	5.4
Clarence	5.2	5.2	5.2	5.2	5.2
Orleans	4.3	6.9	10.1	13.3	16.9
Ottawa-Slater	70.0	80.9	101.1	126.9	159.1
Ottawa-"Montreal Road"	-	40.8	51.0	64.0	80.3
Ottawa-Lisgar	50.2	60.1	75.1	94.3	118.2
Rockland	7.8	14.1	21.5	29.5	38.5
NAE.	0.6	0.6	0.7	0.7	0.8
Hawkesbury	12.5	13.9	13.9	13.9	13.9
Bilberry Creek	9.3	30.4	50.2	73.3	96.6
Nepean(Epworth)	16.0	14.3	14.3	14.3	14.3
Arnprior TS	51.8	52.0	74.3	98.6	127.1
Ottawa-King Edward	62.4	78.7	98.3	123.4	154.7
Ottawa-Hinchey	32.7	43.0	53.8	67.5	84.7
Merivale	16.0	14.3	14.3	14.3	14.3
"Nepean"	-	97.4	134.4	183.2	227.8
Cumberland	6.5	7.8	8.5	8.5	8.5
Manotick	11.3	10.9	8.5	8.5	8.5
Manordale	16.0	14.3	14.3	14.3	14.3
Cyrville	17.1	15.3	15.3	15.3	15.3
Ottawa - "Lincoln Heights"	56.0	69.0	86.2	108.3	135.7
TOTAL PEAK LOAD (MW)	1128.1	1583.1	2095.4	2680.6	3340.3

APPENDIX C



CAPABILITY OF BULK POWER TRANSMISSION SYSTEM
TO SUPPLY THE OTTAWA AREA FOR LOADS HIGHER
AND LOWER THAN THE FORECAST
(Load Coincident with System Winter Peak)

APPENDIX D

AREA ARNPRIOR

DECEMBER PEAK LOADS IN MW

CUSTOMER	ACTUAL 1978	SHORT TERM ESTIMATE 1979	1980	1981	1982	1983	1984	AVERAGE GROWTH RATE 1978-84 %	PROJECTION 1985	1986	1987	1988	AVERAGE GROWTH RATE 1984-88 %
MUNICIPAL													
ARNPRIOR	14.8	16.3	17.2	18.2	19.3	20.4	21.6	6.57	22.9	24.2	25.7	27.2	5.87
BRAESIDE	2.9	2.9	3.0	3.0	3.1	3.1	3.1	1.20	3.2	3.2	3.3	3.3	1.40
RICHMOND	3.7	4.5	4.8	5.1	5.4	5.8	6.2	8.96	6.6	7.0	7.4	7.9	6.43
NEPEAN TWP	122.0	125.6	130.6	137.1	144.0	149.7	155.7	4.15	162.5	169.7	177.1	184.9	4.39
SUBTOTAL	143.4	149.3	155.6	163.4	171.8	179.0	186.6	4.49	195.2	204.1	213.5	223.3	4.59
UNALLOCATED		-8.6	-12.9	-17.6	-18.2	-18.1	-17.7		-17.0	-16.9	-16.9	-17.2	
NET MUNICIPAL	143.4	140.7	142.7	145.9	153.6	160.9	168.9	2.77	178.2	187.3	196.6	206.1	5.10
RETAIL	60.6	73.1	82.0	92.0	103.1	115.6	129.6	13.52	145.3	163.0	182.8	204.9	12.14
UNALLOCATED		-.9	-.9	-.6	.0	.0	.0		-.4	-.9	-1.6	-2.5	
NET RETAIL	60.6	72.3	81.1	91.3	103.1	115.6	129.6	13.52	144.9	162.1	181.2	202.5	11.80
TOTAL CUSTOMERS	204.0	222.4	237.6	255.4	274.9	294.6	316.2	7.58	340.5	367.1	396.2	428.2	7.87
TOTAL UNALLOCATED		-9.5	-13.8	-18.2	-18.2	-18.1	-17.7		-17.4	-17.7	-18.5	-19.7	
NET ALL CUSTOMERS	204.0	212.9	223.8	237.2	256.7	276.5	298.5	6.56	323.1	349.4	377.8	408.6	8.16

AREA ARNPRIOR

DECEMBER PEAK LOADS IN MW

LONG TERM PROJECTION

CUSTOMER **	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	AVERAGE GROWTH RATE 1988-00 %
MUNICIPAL													
ARNPRIOR	26.8	28.4	29.9	31.7	33.3	35.2	37.2	38.8	40.3	41.9	43.7	45.4	5.08
BRAESIDE	3.2	3.3	3.4	3.5	3.6	3.7	3.8	3.9	4.1	4.2	4.3	4.5	3.20
RICHMOND	7.8	8.4	8.9	9.4	10.0	10.6	11.3	11.8	12.4	12.9	13.6	14.2	5.71
NEPEAN TWP	181.2	191.0	199.9	210.4	220.1	231.4	242.7	251.5	260.2	268.9	278.4	287.9	4.45
TOTAL	219.0	231.0	242.0	255.0	267.0	281.0	295.0	306.0	317.0	328.0	340.0	352.0	4.56
RETAIL	216.0	229.6	244.1	259.4	275.7	293.1	311.5	329.9	349.4	370.2	392.1	415.4	6.17
TOTAL IN AREA	435.0	460.6	486.1	514.4	542.7	574.1	606.5	635.9	666.4	698.2	732.1	767.4	5.39

** INCLUDES UNALLOCATED

AREA BROCKVILLE

DECEMBER PEAK LOADS IN MW

CUSTOMER	ACTUAL 1978	SHORT TERM ESTIMATE 1979	1980	1981	1982	1983	1984	AVERAGE GROWTH RATE 1978-84 %	PROJECTION 1985	1986	1987	1988	AVERAGE GROWTH RATE 1984-88 %
MUNICIPAL													
ATHENS	1.6	1.6	1.7	1.8	1.8	1.9	1.9	3.15	2.0	2.1	2.1	2.2	3.26
BROCKVILLE	39.4	41.9	46.7	48.6	50.0	51.5	53.0	5.05	55.5	58.2	61.0	63.9	4.80
CARDINAL	1.8	2.0	2.1	2.2	2.3	2.4	2.4	4.75	2.5	2.6	2.7	2.8	3.71
PRESCOTT	8.0	8.6	9.0	9.4	9.8	10.2	10.6	4.84	11.1	11.6	12.1	12.6	4.33
SUBTOTAL	50.9	54.2	59.5	61.9	63.9	65.9	68.0	4.95	71.2	74.5	78.0	81.6	4.65
UNALLOCATED		-3.1	-4.9	-6.7	-6.8	-6.7	-6.5		-6.2	-6.2	-6.2	-6.3	
NET MUNICIPAL	50.9	51.1	54.6	55.2	57.1	59.3	61.6	3.22	65.0	68.3	71.8	75.3	5.16
INDUSTRIAL													
SUBTOTAL	43.5	44.2	44.6	44.8	45.0	45.2	45.4	.73	45.6	45.8	46.0	46.2	.46
UNALLOCATED		.0	-.6	-1.2	-.6	-1.1	.0		1.2	2.4	3.6	4.9	
NET INDUSTRIAL	43.5	44.2	44.0	43.6	44.4	44.1	45.4	.73	46.8	48.2	49.6	51.1	3.00
RETAIL	54.1	61.1	66.0	71.2	76.9	83.0	89.6	8.76	96.8	104.5	112.9	121.9	7.98
UNALLOCATED		-.7	-.7	-.5	.0	.0	.0		-.3	-.6	-1.0	-1.5	
NET RETAIL	54.1	60.3	65.2	70.7	76.9	83.0	89.6	8.76	96.5	104.0	111.9	120.4	7.66
TOTAL CUSTOMERS	148.5	159.5	170.0	177.9	185.8	194.2	203.1	5.35	213.6	224.8	236.9	249.7	5.31
TOTAL UNALLOCATED		-3.8	-6.3	-8.3	-7.3	-7.8	-6.5		-5.3	-4.3	-3.6	-2.9	
NET ALL CUSTOMERS	148.5	155.6	163.8	169.6	178.4	186.4	196.6	4.79	208.3	220.5	233.3	246.8	5.85

AREA BROCKVILLE

DECEMBER PEAK LOADS IN MW

LONG TERM PROJECTION

CUSTOMER **	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	AVERAGE GROWTH RATE 1988-00 %
MUNICIPAL													
ATHENS	2.1	2.2	2.2	2.3	2.4	2.5	2.6	2.7	2.8	2.9	3.0	3.1	3.56
BROCKVILLE	62.2	64.5	67.9	70.2	73.5	76.8	80.0	83.3	87.4	90.6	93.8	97.8	4.30
CARDINAL	2.7	2.8	2.9	3.0	3.1	3.2	3.3	3.4	3.6	3.7	3.8	4.0	3.57
PRESCOTT	12.0	12.5	13.0	13.5	14.0	14.5	15.0	15.6	16.2	16.8	17.4	18.1	3.74
TOTAL	79.0	82.0	86.0	89.0	93.0	97.0	101.0	105.0	110.0	114.0	118.0	123.0	4.17
INDUSTRIAL TOTAL	53.0	54.0	55.0	57.0	58.0	59.0	61.0	62.0	63.0	65.0	66.0	67.0	2.28
RETAIL	126.5	132.5	138.7	145.2	152.1	159.3	166.8	174.1	181.8	189.8	198.2	207.0	4.62
TOTAL IN AREA	258.5	268.5	279.7	291.2	303.1	315.3	328.8	341.1	354.8	368.8	382.2	397.0	4.04

** INCLUDES UNALLOCATED

AREA KINGSTON

DECEMBER PEAK LOADS IN MW

		SHORT TERM ESTIMATE							PROJECTION				
CUSTOMER	ACTUAL 1978	1979	1980	1981	1982	1983	1984	AVERAGE GROWTH RATE 1978-84 %	1985	1986	1987	1988	AVERAGE GROWTH RATE 1984-88 %
MUNICIPAL													
BATH	1.6	1.9	2.1	2.3	2.5	2.8	3.1	11.33	3.4	3.8	4.2	4.6	10.61
KINGSTON	97.4	105.6	109.3	113.2	117.2	121.4	125.7	4.34	130.2	134.8	139.6	144.6	3.56
NEWBURGH	.7	.8	.8	.8	.9	.9	.9	4.41	.9	1.0	1.0	1.0	2.99
SUBTOTAL	99.7	108.2	112.2	116.3	120.6	125.1	129.7	4.47	134.5	139.5	144.8	150.2	3.74
UNALLOCATED		-6.3	-9.3	-12.5	-12.8	-12.7	-12.3		-11.7	-11.5	-11.5	-11.6	
NET MUNICIPAL	99.7	101.9	102.9	103.8	107.8	112.4	117.4	2.75	122.8	128.0	133.3	138.6	4.25
INDUSTRIAL													
SUBTOTAL	88.5	90.9	97.1	100.2	103.3	105.6	107.8	3.34	110.1	112.5	115.0	117.6	2.20
UNALLOCATED		.0	-1.4	-2.7	-1.3	-2.6	.0		2.9	5.9	8.9	12.3	
NET INDUSTRIAL	88.5	90.9	95.7	97.5	102.0	103.0	107.8	3.34	113.0	118.4	123.9	129.9	4.78
RETAIL	96.3	111.0	118.8	127.2	136.1	145.7	155.9	8.36	166.9	178.6	191.2	204.7	7.04
UNALLOCATED		-1.3	-1.3	-.9	.0	.0	.0		-.5	-1.0	-1.7	-2.5	
NET RETAIL	96.3	109.7	117.5	126.3	136.1	145.7	155.9	8.36	166.4	177.7	189.6	202.2	6.71
TOTAL CUSTOMERS	284.6	310.1	328.1	343.7	360.0	376.3	393.4	5.54	411.5	430.7	451.0	472.5	4.68
TOTAL UNALLOCATED		-7.5	-11.9	-16.1	-14.1	-15.2	-12.3		-9.3	-6.6	-4.2	-1.7	
NET ALL CUSTOMERS	284.6	302.5	316.1	327.6	345.9	361.1	381.1	4.99	402.2	424.1	446.8	470.8	5.42

AREA KINGSTON

DECEMBER PEAK LOADS IN MW

LONG TERM PROJECTION

CUSTOMER **	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	AVERAGE GROWTH RATE 1988-00 %
MUNICIPAL													
BATH	4.4	4.6	4.8	4.9	5.1	5.3	5.5	5.7	5.9	6.2	6.4	6.6	3.80
KINGSTON	138.5	144.3	149.1	154.9	161.7	167.5	174.2	180.0	186.7	194.4	201.1	208.8	3.80
NEWBURGH	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.4	1.4	3.50
TOTAL	143.9	149.9	154.9	160.9	167.9	173.9	180.9	186.9	193.9	201.9	208.9	216.9	3.80
INDUSTRIAL TOTAL	134.0	137.0	141.0	144.0	148.0	151.0	155.0	158.0	161.0	164.0	167.0	170.0	2.27
RETAIL	213.6	225.4	237.9	251.1	265.0	279.7	295.1	311.2	328.1	345.9	364.6	384.4	5.50
TOTAL IN AREA	491.6	512.4	533.9	556.0	580.9	604.6	631.1	656.1	683.0	711.8	740.6	771.3	4.20

** INCLUDES UNALLOCATED

DECEMBER PEAK LOADS IN MW

CUSTOMER	ACTUAL 1978	SHORT TERM ESTIMATE 1979	1980	1981	1982	1983	1984	AVERAGE GROWTH RATE 1978-84 %	PROJECTION 1985	1986	1987	1988	AVERAGE GROWTH RATE 1984-88 %
MUNICIPAL													
ALMONTE	5.4	5.8	6.0	6.2	6.5	6.7	7.0	4.34	7.3	7.6	7.9	8.2	3.93
CARLETON PLACE	9.2	10.2	10.8	11.5	12.2	13.0	13.7	6.83	14.5	15.4	16.3	17.3	6.05
LANARK	1.1	1.2	1.2	1.3	1.3	1.3	1.4	4.03	1.4	1.5	1.5	1.6	3.37
MERRICKVILLE	1.8	1.9	2.0	2.2	2.3	2.5	2.7	7.29	2.9	3.2	3.4	3.7	7.76
NEWBORO	.4	.5	.5	.5	.5	.5	.6	5.60	.6	.6	.6	.7	3.89
PERTH	11.7	13.2	14.0	14.7	15.6	16.5	17.4	6.90	18.4	19.5	20.6	21.7	5.70
SMITHS FALLS	16.5	17.7	18.1	18.5	18.9	19.3	19.7	3.01	20.2	20.6	21.1	21.5	2.22
WESTPORT	1.4	1.5	1.6	1.7	1.9	2.0	2.1	7.83	2.3	2.4	2.6	2.8	6.94
SUBTOTAL	47.4	51.9	54.2	56.6	59.2	61.8	64.6	5.29	67.6	70.7	74.0	77.4	4.63
UNALLOCATED		-3.0	-4.5	-6.1	-6.3	-6.3	-6.1		-5.9	-5.8	-5.9	-6.0	
NET MUNICIPAL	47.4	48.9	49.7	50.5	52.9	55.6	58.5	3.55	61.7	64.9	68.1	71.5	5.14
RETAIL	49.3	61.7	68.1	75.1	82.9	91.4	100.9	12.67	111.4	122.9	135.6	149.7	10.35
UNALLOCATED		-.7	-.7	-.5	.0	.0	.0		-.3	-.7	-1.2	-1.8	
NET RETAIL	49.3	60.9	67.3	74.6	82.9	91.4	100.9	12.67	111.0	122.2	134.4	147.9	10.02
TOTAL CUSTOMERS	96.8	113.5	122.2	131.7	142.0	153.3	165.5	9.36	178.9	193.6	209.6	227.1	8.23
TOTAL UNALLOCATED		-3.7	-5.2	-6.6	-6.3	-6.3	-6.1		-6.2	-6.5	-7.0	-7.8	
NET ALL CUSTOMERS	96.8	109.8	117.0	125.1	135.8	147.0	159.4	8.68	172.7	187.1	202.6	219.3	8.31

AREA PERTH

DECEMBER PEAK LOADS IN MW

LONG TERM PROJECTION

CUSTOMER **	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	AVERAGE GROWTH RATE 1988-00 %
MUNICIPAL													
ALMONTE	8.1	8.3	8.7	9.1	9.5	9.9	10.4	10.6	10.7	11.1	11.2	11.5	3.59
CARLETON PLACE	17.3	18.1	19.2	20.3	21.4	22.5	23.9	24.7	25.4	26.5	27.2	28.3	4.87
LANARK	1.6	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.4	4.42
MERRICKVILLE	3.5	3.6	3.8	3.9	4.1	4.2	4.4	4.6	4.8	5.0	5.2	5.4	3.94
NEWBORO	.7	.7	.7	.8	.8	.8	.9	.9	.9	1.0	1.0	1.0	4.42
PERTH	21.7	22.6	23.9	25.3	26.6	27.9	29.6	30.4	31.3	32.5	33.3	34.6	4.64
SMITHS FALLS	20.4	21.1	21.9	22.6	23.4	24.2	25.0	25.8	26.7	27.6	28.5	29.5	3.35
WESTPORT	2.8	2.9	3.1	3.2	3.4	3.6	3.8	3.9	4.0	4.1	4.2	4.3	4.42
TOTAL	76.0	79.0	83.0	87.0	91.0	95.0	100.0	103.0	106.0	110.0	113.1	117.1	4.20
RETAIL	156.0	164.6	173.6	183.2	193.2	203.9	215.1	226.9	239.3	252.5	266.3	280.9	5.49
TOTAL IN AREA	232.0	243.6	256.7	270.2	284.3	298.9	315.1	329.9	345.4	362.5	379.4	398.0	5.09

** INCLUDES UNALLOCATED

AREA VANKLEEK HILL

DECEMBER PEAK LOADS IN MW

CUSTOMER	ACTUAL 1978	SHORT TERM ESTIMATE 1979	1980	1981	1982	1983	1984	AVERAGE GROWTH RATE 1978-84 %	PROJECTION 1985	1986	1987	1988	AVERAGE GROWTH RATE 1984-88 %
MUNICIPAL													
ALEXANDRIA	7.9	8.8	9.2	9.6	10.1	10.5	11.0	5.67	11.5	12.0	12.5	13.1	4.50
ALFRED	2.6	2.9	3.1	3.3	3.5	3.7	4.0	7.39	4.2	4.5	4.8	5.2	6.74
APPLE HILL	.3	.4	.4	.4	.4	.5	.5	6.06	.5	.5	.5	.6	4.44
CASSELMAN	3.6	4.1	4.4	4.8	5.2	5.7	6.2	9.68	6.7	7.3	8.0	8.7	8.79
HAWKESBURY	27.0	33.2	37.1	41.4	46.3	51.7	57.8	13.51	64.6	72.2	80.7	90.2	11.75
LANCASTER	1.2	1.3	1.3	1.4	1.5	1.6	1.6	5.22	1.7	1.8	1.9	2.0	4.96
L ORIGNAL	3.0	3.0	3.3	3.6	3.9	4.2	4.6	7.45	5.0	5.4	5.9	6.4	8.85
MARTINTOWN	.3	.4	.4	.4	.4	.4	.4	3.96	.4	.4	.4	.5	2.71
MAXVILLE	1.5	1.8	1.9	1.9	2.0	2.1	2.2	6.51	2.3	2.4	2.4	2.5	3.82
ROCKLAND	6.3	6.5	7.0	7.6	8.2	8.9	9.6	7.24	10.3	11.2	12.0	13.0	7.96
VANKLEEK HILL	3.0	3.3	3.6	3.9	4.3	4.7	5.1	9.67	5.6	6.1	6.7	7.3	9.35
PLANTAGENET	1.9	2.2	2.3	2.4	2.5	2.6	2.7	6.46	2.8	2.9	3.1	3.2	4.21
SUBTOTAL	58.5	67.8	74.0	80.8	88.3	96.6	105.7	10.35	115.7	126.8	139.1	152.6	9.62
UNALLOCATED		-3.9	-6.1	-8.7	-9.4	-9.8	-10.0		-10.1	-10.5	-11.0	-11.8	
NET MUNICIPAL	58.5	63.9	67.9	72.1	79.0	86.8	95.7	8.54	105.7	116.4	128.1	140.9	10.16
INDUSTRIAL													
SUBTOTAL	134.0	133.5	133.8	135.5	138.4	164.6	165.2	3.56	165.8	166.4	167.0	167.7	.37
UNALLOCATED		.0	-1.9	-3.6	-1.8	-4.0	.0		4.4	8.7	13.0	17.6	
NET INDUSTRIAL	134.0	133.5	131.9	131.9	136.6	160.6	165.2	3.56	170.2	175.1	180.0	185.3	2.91
RETAIL	76.3	85.2	91.6	98.5	105.9	113.8	122.3	8.18	131.5	141.4	152.0	163.4	7.50
UNALLOCATED		-1.0	-1.0	-.7	.0	.0	.0		-.4	-.8	-1.3	-2.0	
NET RETAIL	76.3	84.2	90.6	97.8	105.9	113.8	122.3	8.18	131.1	140.6	150.7	161.4	7.18
TOTAL CUSTOMERS	268.8	286.5	299.4	314.8	332.6	375.0	393.2	6.55	413.1	434.6	458.1	483.7	5.31
TOTAL UNALLOCATED		-4.9	-9.0	-13.0	-11.2	-13.8	-10.0		-6.1	-2.6	.6	3.9	
NET ALL CUSTOMERS	268.8	281.6	290.4	301.9	321.5	361.2	383.2	6.09	407.0	432.1	458.8	487.6	6.21

AREA VANKLEEK HILL

LONG TERM PROJECTION

DECEMBER PEAK LOADS IN MW

CUSTOMER **	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	AVERAGE GROWTH RATE 1988-00 %
MUNICIPAL													
ALEXANDRIA	12.8	13.3	13.9	14.5	15.1	15.7	16.4	16.9	17.5	18.0	18.6	19.2	3.94
ALFRED	5.3	5.6	6.0	6.4	6.8	7.3	7.7	7.8	7.9	8.0	8.2	8.4	4.83
APPLE HILL	.5	.6	.6	.6	.6	.6	.7	.7	.7	.7	.8	.8	3.50
CASSELMAN	8.4	8.8	9.2	9.6	10.0	10.4	10.9	11.3	11.7	12.1	12.5	12.9	4.06
HAWKESBURY	88.6	92.8	97.5	102.3	107.0	112.3	117.7	121.8	126.0	130.2	135.0	139.8	4.42
LANCASTER	1.9	2.0	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.6	2.7	2.8	3.50
L ORIGNAL	6.7	7.2	7.8	8.3	8.9	9.6	10.2	10.5	10.8	11.0	11.4	11.7	5.78
MARTINTOWN	.4	.5	.5	.5	.5	.5	.5	.6	.6	.6	.6	.6	3.50
MAXVILLE	2.4	2.5	2.6	2.7	2.8	2.9	3.0	3.0	3.1	3.2	3.3	3.4	3.06
ROCKLAND	12.7	13.3	14.0	14.7	15.4	16.2	17.0	17.8	18.6	19.4	20.3	21.3	4.90
VANKLEEK HILL	7.1	7.3	7.6	7.9	8.2	8.6	8.9	9.2	9.6	9.9	10.3	10.7	3.88
PLANTAGENET	3.1	3.2	3.3	3.4	3.5	3.6	3.8	3.9	4.0	4.2	4.3	4.4	3.49
TOTAL	150.0	157.0	165.0	173.0	181.0	190.0	199.0	206.0	213.0	220.0	228.0	236.0	4.39
INDUSTRIAL TOTAL	191.0	196.0	201.0	205.0	211.0	216.0	221.0	225.0	230.0	234.0	238.0	243.0	2.29
RETAIL	172.6	182.8	193.5	204.9	216.8	229.4	242.6	254.2	266.3	278.8	291.9	305.4	5.46
TOTAL IN AREA	513.6	535.8	559.5	582.9	608.8	635.4	662.6	685.2	709.3	732.8	757.9	784.4	4.04

** INCLUDES UNALLOCATED

AREA WINCHESTER

DECEMBER PEAK LOADS IN MW

CUSTOMER	ACTUAL 1978	SHORT TERM ESTIMATE 1979	1980	1981	1982	1983	1984	AVERAGE GROWTH RATE 1978-84 %	PROJECTION 1985	1986	1987	1988	AVERAGE GROWTH RATE 1984-88 %
MUNICIPAL													
AVONMORE	.3	.3	.4	.4	.4	.4	.4	3.43	.4	.4	.4	.4	2.53
CHESTERVILLE	4.0	4.3	4.7	5.1	5.5	5.9	6.4	7.85	6.9	7.4	8.0	8.6	7.93
FINCH	.8	.8	.9	.9	1.0	1.0	1.1	5.80	1.1	1.2	1.2	1.3	4.53
IROQUOIS	3.7	3.8	3.9	3.9	4.0	4.1	4.2	2.18	4.4	4.5	4.6	4.7	2.52
KEMPTVILLE	5.1	5.8	6.0	6.3	6.6	6.8	7.1	5.81	7.4	7.7	8.1	8.4	4.28
MORRISBURG	5.0	4.8	5.1	5.5	5.9	6.4	6.9	5.54	7.4	7.9	8.5	9.2	7.55
OTTAWA	575.4	620.0	633.0	652.0	678.0	712.0	755.0	4.63	785.3	816.9	849.7	883.9	4.02
RUSSELL	1.8	2.1	2.3	2.5	2.7	2.9	3.2	10.08	3.5	3.8	4.2	4.5	9.13
WILLIAMSBURG	.5	.5	.5	.6	.6	.6	.6	3.95	.6	.7	.7	.7	3.54
WINCHESTER	5.8	5.7	6.1	6.7	7.2	7.8	8.5	6.50	9.2	10.0	10.8	11.7	8.39
EMBRUN	4.1	4.8	5.2	5.6	6.1	6.6	7.1	9.63	7.7	8.4	9.1	9.8	8.37
GLOUCESTER TWP	83.7	91.6	97.6	104.4	111.7	120.1	129.7	7.57	139.0	149.0	159.8	171.3	7.20
SUBTOTAL	690.2	744.5	765.6	793.8	829.6	874.7	930.2	5.10	973.0	1017.9	1065.0	1114.5	4.62
UNALLOCATED		-43.0	-63.3	-85.4	-87.8	-88.6	-88.2		-84.8	-84.1	-84.3	-85.8	
NET MUNICIPAL	690.2	701.4	702.3	708.4	741.7	786.1	841.9	3.37	888.2	933.8	980.8	1028.7	5.14
RETAIL*	116.9	143.1	155.8	169.7	185.0	201.7	220.1	11.12	240.3	262.5	287.0	313.8	9.28
UNALLOCATED		-1.5	-1.7	-1.5	-.2	-.4	.0		-.3	-.5	-1.2	-2.0	
NET RETAIL*	116.9	141.6	154.1	168.2	184.8	201.3	220.1	11.12	240.0	262.0	285.8	311.8	9.10
TOTAL CUSTOMERS	807.1	887.6	921.4	963.5	1014.5	1076.4	1150.2	6.08	1213.2	1280.4	1352.0	1428.3	5.56
TOTAL UNALLOCATED		-44.5	-65.0	-86.9	-88.0	-88.9	-88.2		-85.0	-84.6	-85.5	-87.8	
NET ALL CUSTOMERS	807.1	843.0	856.4	876.6	926.5	987.4	1062.0	4.68	1128.2	1195.8	1266.5	1340.5	6.00

* INCLUDES INDUSTRIAL CUSTOMERS

AREA WINCHESTER

DECEMBER PEAK LOADS IN MW

LONG TERM PROJECTION

CUSTOMER **	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	AVERAGE GROWTH RATE 1988-00 %
MUNICIPAL													
AVONMORE	.4	.4	.4	.5	.5	.5	.5	.5	.5	.6	.6	.6	3.50
CHESTERVILLE	8.5	9.0	9.5	10.0	10.5	11.1	11.6	12.0	12.5	12.9	13.3	13.8	4.66
FINCH	1.2	1.2	1.3	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.7	1.8	3.50
IROQUOIS	4.6	4.9	5.1	5.3	5.6	5.8	6.1	6.3	6.4	6.6	6.8	7.0	4.09
KEMPTVILLE	8.1	8.3	8.6	8.9	9.2	9.6	9.9	10.2	10.6	11.0	11.4	11.8	3.51
MORRISBURG	9.1	9.6	10.2	10.7	11.3	11.9	12.6	13.0	13.5	14.0	14.5	15.1	4.93
OTTAWA	854.6	894.7	936.5	980.3	1026.1	1074.0	1124.3	1176.1	1230.6	1287.3	1346.8	1409.0	4.66
RUSSELL	4.3	4.5	4.7	4.9	5.1	5.3	5.5	5.7	5.9	6.1	6.3	6.6	3.84
WILLIAMSBURG	.7	.7	.7	.8	.8	.8	.8	.9	.9	.9	1.0	1.0	3.50
WINCHESTER	11.3	11.8	12.3	12.8	13.3	13.9	14.5	15.1	15.8	16.5	17.2	17.9	4.30
EMBRUN	9.5	10.0	10.4	10.9	11.5	12.0	12.6	13.2	13.8	14.5	15.2	15.9	4.80
GLOUCESTER TWP	171.6	183.8	196.2	209.5	222.8	237.7	253.2	265.4	278.8	291.9	306.2	320.6	6.07
TOTAL	1084.0	1139.0	1196.0	1256.0	1318.0	1384.0	1453.0	1520.0	1591.0	1664.0	1741.0	1821.0	4.87
RETAIL*	333.0	353.1	373.3	394.6	418.1	441.8	467.8	489.8	513.7	537.6	562.4	589.3	5.45
TOTAL IN AREA	1417.0	1492.1	1569.3	1650.6	1736.1	1825.8	1920.8	2009.8	2104.7	2201.6	2303.4	2410.3	5.01

* INCLUDES INDUSTRIAL CUSTOMERS

** INCLUDES UNALLOCATED

APPENDIX E

EASTERN ONTARIO

SCENARIO 1

ELECTRIC ENERGY MARKETS

	HISTORY 1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976
ELECTRIC ENERGY CONSUMPTION												
RESIDENTIAL (GWH)												
SPACE HEATING	60.	73.	74.	76.	99.	124.	157.	180.	254.	331.	362.	469.
WATER HEATING	796.	839.	856.	879.	906.	925.	946.	939.	1002.	1069.	1103.	1150.
APPLIANCES ETC.	439.	464.	559.	637.	681.	746.	786.	837.	841.	852.	868.	958.
TOTAL RESIDENTIAL ELECTRICITY	1295.	1376.	1489.	1592.	1686.	1795.	1889.	2006.	2097.	2252.	2333.	2577.
TOTAL FARM (GWH)	144.	150.	169.	182.	196.	208.	220.	226.	238.	260.	268.	289.
COMMERCIAL (GWH)												
HEATING	56.	64.	74.	83.	93.	104.	118.	136.	153.	170.	174.	193.
OTHER(MOTORS + LIGHTING)	901.	1047.	1205.	1347.	1504.	1693.	1911.	2217.	2477.	2757.	2780.	3143.
STREET LIGHTING	30.	32.	33.	34.	36.	38.	41.	42.	48.	50.	56.	60.
TOTAL COMMERCIAL ELECTRICITY	987.	1143.	1312.	1464.	1633.	1835.	2070.	2395.	2678.	2977.	3010.	3396.
INDUSTRIAL												
MANUFACTURING (GWH)												
ALUMINUM												
PULP + PAPER	307.	334.	316.	341.	349.	357.	340.	345.	336.	289.	281.	271.
CHEMICALS	442.	467.	457.	438.	457.	448.	452.	462.	466.	493.	453.	421.
STEEL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
LIGHT MANUFACTURING	709.	747.	769.	821.	889.	993.	1029.	1148.	1223.	1304.	1333.	1441.
*OTHER HEAVY MANUFACTURING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SUBTOTAL-MANUFACTURING	1458.	1548.	1542.	1600.	1695.	1798.	1821.	1955.	2025.	2086.	2067.	2133.
MINING (GWH)												
IRON	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
COPPER	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
COAL												
OTHER	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SUBTOTAL-MINING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL INDUSTRIAL ELECTRICITY	1458.	1548.	1542.	1600.	1695.	1798.	1821.	1955.	2025.	2086.	2067.	2133.
*TOTAL OTHER												
TOTAL CONSUMPTION (GWH)	3884.	4217.	4512.	4838.	5210.	5636.	6000.	6582.	7038.	7575.	7678.	8395.
LOSSES AND EXPORTS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL DISPOSABLE ENERGY (GWH)	3884.	4217.	4512.	4838.	5210.	5636.	6000.	6582.	7038.	7575.	7678.	8395.

SCENARIO 1

EASTERN ONTARIO

ELECTRIC ENERGY MARKETS

	FORECAST 1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1990	1995	2000	2005
ELECTRIC ENERGY CONSUMPTION														
RESIDENTIAL (GWH)														
SPACE HEATING	548.	621.	691.	757.	820.	880.	937.	992.	1045.	1095.	1280.	1533.	1766.	2056.
WATER HEATING	1064.	996.	943.	901.	870.	846.	829.	818.	810.	807.	815.	849.	899.	956.
APPLIANCES ETC.	1009.	1054.	1101.	1148.	1198.	1250.	1304.	1361.	1420.	1461.	1736.	2013.	2333.	2704.
TOTAL RESIDENTIAL ELECTRICITY	2621.	2672.	2734.	2807.	2888.	2976.	3071.	3170.	3274.	3383.	3531.	4370.	4998.	5717.
TOTAL FARM (GWH)	294.	300.	307.	315.	324.	333.	343.	354.	365.	376.	423.	479.	543.	616.
COMMERCIAL (GWH)														
HEATING	350.	512.	678.	847.	1020.	1197.	1377.	1561.	1750.	1942.	2743.	3805.	5030.	6459.
OTHER(MOTORS + LIGHTING)	3370.	3582.	3302.	4034.	4280.	4541.	4818.	5111.	5423.	5731.	7032.	8567.	10432.	12704.
STREET LIGHTING	63.	66.	68.	71.	74.	77.	80.	84.	87.	91.	106.	123.	142.	165.
TOTAL COMMERCIAL ELECTRICITY	3783.	4160.	4548.	4952.	5374.	5815.	6275.	6756.	7260.	7765.	9881.	12494.	15605.	19328.
INDUSTRIAL														
MANUFACTURING (GWH)														
ALUMINUM	278.	285.	292.	299.	306.	314.	322.	330.	338.	346.	379.	405.	439.	473.
PULP + PAPER	438.	455.	473.	492.	512.	532.	553.	575.	598.	622.	720.	834.	966.	1120.
CHEMICALS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
STEEL	1489.	1539.	1591.	1645.	1700.	1757.	1816.	1877.	1940.	2005.	2270.	2570.	2910.	3294.
LIGHT MANUFACTURING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
*OTHER HEAVY MANUFACTURING														
SUBTOTAL-MANUFACTURING	2205.	2279.	2356.	2436.	2518.	2603.	2691.	2782.	2876.	2973.	3368.	3812.	4315.	4887.
MINING (GWH)														
IRON	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
COPPER	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
COAL														
OTHER	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SUBTOTAL-MINING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL INDUSTRIAL ELECTRICITY	2205.	2279.	2356.	2436.	2518.	2603.	2691.	2782.	2876.	2973.	3368.	3812.	4315.	4887.
*TOTAL OTHER														
TOTAL CONSUMPTION (GWH)	8903.	9411.	9946.	10510.	11104.	11727.	12380.	13062.	13775.	14497.	17503.	21155.	25460.	30548.
LOSSES AND EXPORTS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL DISPOSABLE ENERGY (GWH)	8903.	9411.	9946.	10510.	11104.	11727.	12380.	13062.	13775.	14497.	17503.	21155.	25460.	30548.

SCENARIO 1

EASTERN ONTARIO

COMPETITIVE ENERGY MARKETS AND PRICES

	HISTORY 1965	******** 1966	******** 1967	******** 1968	******** 1969	******** 1970	******** 1971	******** 1972	******** 1973	******** 1974	******** 1975	******** 1976
COMPETITIVE ENERGY MARKETS												
RESIDENTIAL												
SPACE HEATING-MARKET SHARES												
PCT HOUSEHOLDS-ELECTRIC	1.8	2.1	2.1	2.1	2.7	3.3	4.1	4.6	6.3	8.0	8.5	10.7
PCT HOUSEHOLDS-GAS	29.1	29.1	32.3	34.2	36.9	38.4	39.8	41.8	40.8	42.2	43.5	46.7
PCT HOUSEHOLDS-OIL	60.8	59.2	58.5	57.9	55.9	55.2	53.8	52.3	51.6	48.6	47.0	41.7
PCT HOUSEHOLDS-SOLIDS	8.3	9.6	7.1	5.8	4.5	3.1	2.3	1.3	1.3	1.2	1.0	0.9
TOTAL-PCT	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
TOTAL SPACE HEATING REQUIREMENTS-GWH EQUIVALENT	3333.	3476.	3523.	3619.	3667.	3758.	3829.	3913.	4032.	4138.	4258.	4383.
WATER HEATING-MARKET SHARES												
PCT HOUSEHOLDS-ELECTRIC	79.3	79.9	80.5	81.1	81.7	82.2	82.5	81.7	81.5	85.2	86.4	87.4
PCT HOUSEHOLDS-GAS	10.7	9.1	10.2	9.2	11.0	10.7	9.1	8.1	7.9	5.8	6.6	6.6
PCT HOUSEHOLDS-OIL	2.4	2.5	2.3	2.7	3.4	3.9	5.0	5.7	5.3	6.1	5.3	4.5
PCT HOUSEHOLDS-SOLIDS	7.6	8.5	7.0	7.0	3.9	3.2	3.4	4.5	5.3	2.9	1.7	1.5
TOTAL-PCT	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
TOTAL WATER HEATING REQUIREMENTS-GWH EQUIVALENT	1004.	1050.	1063.	1084.	1109.	1125.	1147.	1211.	1229.	1254.	1277.	1316.
COMMERCIAL												
HEATING-USEFUL ENERGY-PCT												
MARKET SHARE-ELECTRIC	1.4	1.5	1.6	1.6	1.6	1.7	1.8	1.8	1.9	2.0	2.0	2.1
MARKET SHARE-GAS	30.4	28.8	33.2	33.3	38.1	39.4	43.8	47.2	52.6	61.9	74.0	73.7
MARKET SHARE-OIL	56.3	61.0	57.8	59.4	55.6	55.6	52.4	49.5	45.0	35.7	24.0	24.2
MARKET SHARE-SOLIDS	11.9	8.7	7.4	5.7	4.7	3.3	2.0	1.5	0.5	0.4	0.0	0.0
TOTAL PCT	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
TOTAL COMMERCIAL HEATING REQUIREMENTS-GWH EQUIVALENT	4000.	4267.	4625.	5188.	5813.	6118.	6556.	7556.	8053.	8500.	8700.	9190.
NEW HOUSING-PCT ELECTRIC SPACE	14.8	22.3	16.8	13.2	16.8	18.0	24.2	25.1	24.5	24.0	25.7	30.1
ENERGY PRICES												
RESIDENTIAL RATES												
ELECTRICITY-C/KWH	1.30	1.29	1.29	1.33	1.38	1.43	1.50	1.54	1.65	1.76	1.96	2.24
ELECTRICITY-$/MIL BTU	3.80	3.80	3.80	3.90	4.00	4.20	4.40	4.50	4.80	5.20	5.70	6.56
GAS-$/MIL BTU	1.23	1.24	1.22	1.22	1.21	1.22	1.21	1.21	1.23	1.32	1.66	2.16
OIL-$/MIL BTU	1.09	1.09	1.13	1.19	1.22	1.26	1.32	1.38	1.56	1.95	2.22	2.61
COMMERCIAL RATES												
ELECTRICITY-C/KWH	1.36	1.32	1.31	1.33	1.33	1.34	1.40	1.44	1.34	1.45	1.60	1.85
ELECTRICITY-$/MIL BTU	3.98	3.87	3.84	3.90	3.90	3.93	4.10	4.22	3.92	4.24	4.69	5.42
GAS-$/MIL BTU	0.95	0.94	0.93	0.91	0.88	0.87	0.87	0.86	0.88	0.98	1.27	1.78
OIL-$/MIL BTU	0.79	0.79	0.83	0.89	0.92	0.96	1.02	1.06	1.26	1.65	1.92	2.31
INDUSTRIAL RATES												
ELECTRICITY-C/KWH	0.74	0.73	0.74	0.78	0.82	0.86	0.92	0.94	0.86	0.94	1.09	1.32

EASTERN ONTARIO

SCENARIO 1

COMPETITIVE ENERGY MARKETS AND PRICES

	FORECAST 1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1990	1995	2000	2005
COMPETITIVE ENERGY MARKETS														
RESIDENTIAL														
SPACE HEATING-MARKET SHARES														
PCT HOUSEHOLDS-ELECTRIC	12.3	13.8	15.1	16.3	17.4	18.4	19.3	20.1	20.9	21.6	23.9	26.6	29.5	32.5
PCT HOUSEHOLDS-GAS														
PCT HOUSEHOLDS-OIL														
PCT HOUSEHOLDS-SOLIDS														
TOTAL-PCT														
TOTAL SPACE HEATING REQUIREMENTS-GWH EQUIVALENT	4450.	4515.	4580.	4646.	4714.	4783.	4854.	4925.	4998.	5072.	5362.	5666.	5989.	6332.
WATER HEATING-MARKET SHARES														
PCT HOUSEHOLDS-ELECTRIC	79.5	73.2	68.2	64.1	60.9	58.3	56.3	54.6	53.3	52.2	49.8	48.7	48.4	48.4
PCT HOUSEHOLDS-GAS														
PCT HOUSEHOLDS-OIL														
PCT HOUSEHOLDS-SOLIDS														
TOTAL-PCT														
TOTAL WATER HEATING REQUIREMENTS-GWH EQUIVALENT	1339.	1361.	1383.	1405.	1428.	1451.	1474.	1497.	1520.	1544.	1638.	1744.	1857.	1976.
COMMERCIAL														
HEATING-USEFUL ENERGY-PCT														
MARKET SHARE-ELECTRIC	3.7	5.1	6.6	7.9	9.2	10.4	11.6	12.7	13.7	14.8	18.4	22.4	26.1	29.4
MARKET SHARE-GAS														
MARKET SHARE-OIL														
MARKET SHARE-SOLIDS														
TOTAL PCT														
TOTAL COMMERCIAL HEATING REQUIREMENTS-GWH EQUIVALENT	9575.	9958.	10341.	10725.	11114.	11508.	11910.	12320.	12739.	13168.	14910.	16956.	19283.	21939.
NEW HOUSING-PCT ELECTRIC SPACE														
ENERGY PRICES														
RESIDENTIAL RATES														
ELECTRICITY-C/KWH	2.40	2.57	2.75	2.94	3.15	3.37	3.61	3.87	4.14	4.43	5.71	7.30	9.34	11.94
ELECTRICITY-$/MIL BTU	7.02	7.52	8.05	[illegible].62	9.23	9.88	10.58	11.32	12.12	12.98	16.73	21.39	27.35	34.97
GAS-$/MIL BTU	2.34	2.53	2.73	2.95	3.19	3.45	3.73	4.03	4.36	4.72	6.32	8.49	11.41	15.32
OIL-$/MIL BTU	2.77	2.93	3.11	3.30	3.49	3.70	3.92	4.16	4.41	4.67	5.91	7.93	10.66	14.31
COMMERCIAL RATES														
ELECTRICITY-C/KWH	2.00	2.16	2.34	2.53	2.73	2.96	3.20	3.45	3.74	4.04	5.36	6.86	8.77	11.21
ELECTRICITY-$/MIL BTU	5.86	6.34	6.85	7.41	8.01	8.66	9.36	10.12	10.94	11.83	15.71	20.09	25.68	32.84
GAS-$/MIL BTU	1.94	2.12	2.32	2.53	2.76	3.01	3.29	3.59	3.92	4.28	5.91	7.94	10.67	14.34
OIL-$/MIL BTU	2.45	2.60	2.75	2.92	3.09	3.28	3.47	3.68	3.90	4.14	5.23	7.02	9.43	12.67
INDUSTRIAL RATES														
ELECTRICITY-C/KWH	1.43	1.54	1.67	1.80	1.95	2.11	2.28	2.46	2.67	2.88	3.83	4.89	6.26	8.00

SCENARIO 1

EASTERN ONTARIO

MACRO ECONOMIC INDICATORS AND INDUSTRIAL OUTPUT

	FORECAST 1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1990	1995	2000	2005
ECONOMIC INDICATORS														
GROSS DOMESTIC PROVINCIAL PRODUCT(MILLIONS OF 1976$)	7530.	7816.	8113.	8421.	8741.	9073.	9418.	9776.	10147.	10533.	12157.	14233.	16658.	19499.
GDPP-MANUFACTURING(MILS 1976$)	2260.	2337.	2417.	2500.	2585.	2673.	2765.	2859.	2957.	3058.	[illegible]	[illegible]	4545.	5197.
GDPP-AGRICULTURE(MILS 1976$)	117.	119.	120.	122.	124.	126.	128.	130.	132.	134.	142.	151.	161.	171.
POPULATION(THOUSANDS)	913.	926.	938.	951.	964.	977.	991.	1004.	1018.	1032.	1088.	1153.	1223.	1296.
GDPP-$/CAPITA (1976$)	8244.	8442.	8645.	8852.	9065.	9282.	9505.	9733.	9967.	10206.	11177.	12341.	13625.	15043.
TOTAL EMPLOYMENT(THOUSANDS)	373.	382.	392.	401.	411.	421.	432.	442.	453.	464.	508.	551.	598.	648.
EMPLOYMENT-SERVICE SECTOR(000)	290.	300.	310.	320.	330.	341.	352.	364.	376.	388.	439.	498.	566.	643.
HOUSEHOLDS(THOUSANDS)	250.	256.	262.	269.	276.	282.	289.	296.	304.	311.	341.	374.	411.	451.
INDUSTRIAL PRODUCTION														
ALUMINUM (000 TONS)														
WOOD PULP (000 TONS)	176.	181.	187.	192.	198.	204.	210.	217.	223.	230.	256.	283.	312.	345.
CHEMICALS (MILS $ OF SHIP)	110.0	115.0	120.2	125.6	131.2	137.1	143.3	149.7	156.5	163.5	193.1	229.4	272.4	323.6
STEEL (000 NET TONS)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
MINING														
IRON ORE (000 TONS)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
COPPER (000 TONS)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
COAL (000 TONS)														
OTHER (000 TONS)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL MINING ACTIVITY-000 TONS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

EASTERN ONTARIO

SCENARIO 1

MACRO ECONOMIC INDICATORS AND INDUSTRIAL OUTPUT

	HISTORY 1965	******** 1966	******** 1967	******** 1968	******** 1969	******** 1970	******** 1971	******** 1972	******** 1973	******** 1974	******** 1975	******** 1976
ECONOMIC INDICATORS												
GROSS DOMESTC PROVINCIAL PRODUCT(MILLIONS OF 1976$)	4230.	4165.	4655.	4952.	5325.	5381.	5610.	6051.	6386.	6623.	6658.	7254.
GDPP-MANUFACTURING(MILS 1976$)	1291.	1377.	1417.	1506.	1627.	1569.	1662.	1805.	1943.	1989.	1894.	2185.
GDPP-AGRICULTURE(MILS 1976$)	97.	108.	99.	107.	113.	117.	115.	111.	93.	80.	96.	115.
POPULATION(THOUSANDS)	728.	740.	749.	761.	782.	785.	793.	820.	830.	852.	880.	901.
GDPP-$/CAPITA (1976$)	5811.	5628.	6215.	6507.	6809.	6855.	7074.	7379.	7694.	7773.	7566.	8051.
TOTAL EMPLOYMENT(THOUSANDS)	261.	270.	275.	280.	294.	292.	296.	311.	327.	342.	351.	364.
EMPLOYMENT-SERVICE SECTOR(000)	170.	179.	185.	193.	206.	210.	215.	230.	242.	256.	269.	281.
HOUSEHOLDS(THOUSANDS)	186.	194.	196.	200.	205.	208.	212.	217.	224.	230.	236.	244.
INDUSTRIAL PRODUCTION												
ALUMINUM (000 TONS)												
WOOD PULP (000 TONS)	206.	224.	212.	228.	244.	253.	241.	235.	239.	254.	191.	171.
CHEMICALS (MILS $ OF SHIP)	53.0	56.0	54.8	52.6	56.9	58.2	58.8	64.7	74.6	103.5	117.8	105.3
STEEL (000 NET TONS)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
MINING												
IRON ORE (000 TONS)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
COPPER (000 TONS)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
COAL (000 TONS)												
OTHER (000 TONS)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL MINING ACTIVITY-000 TONS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

APPENDIX F

NORTHEAST POWER COORDINATING COUNCIL
1250 BROADWAY/NEW YORK, N.Y. 10001 TELEPHONE 212/868-1400

BASIC CRITERIA FOR DESIGN AND OPERATION OF INTERCONNECTED POWER SYSTEMS

Originally adopted by the members of the Northeast Power Coordinating Council, September 20, 1967. Revision adopted by the members of the Northeast Power Coordinating Council, July 31, 1970. Revision adopted by the members of the Northeast Power Coordinating Council, June 6, 1975.

C O N T E N T S

1. INTRODUCTION

The purpose of the Northeast Power Coordinating Council is to improve the reliability and efficiency of the interconnected power systems of its members through improved coordination in system design and operating procedures.

One of the steps in reaching this objective is the development of criteria that will be used in the design and operation of the major interconnected power systems. Definitions of several terms used in the following paragraphs are listed in the Appendix.

It is recognized that more rigid criteria will be applied in some segments of the Council area because of local considerations. It is also recognized that the basic criteria are not necessarily applicable to those elements of the individual members' systems that are not a major part of the interconnected transmission network.

The transmission criteria are applicable either to the areas (New Brunswick, New England, New York or Ontario) or to the entire Council interconnection in its relations with neighboring "pools".

An interconnected power system should be designed and operated at a level of reliability such that the loss of a major portion of the system would not result from reasonably foreseeable contingencies. In determining this reliability, it would be desirable to give consideration to all combinations of contingencies occurring more frequently than once in some stipulated number of years. However, sufficient data and techniques

are not available at the present time to define all the contingencies that could occur or to assess and rank their probability of occurrence. Therefore, it is proposed that the interconnected power systems be designed and operated to meet certain specific contingencies. Loss of small portions of the system (such as radial portions) may be tolerated, provided that these do not jeopardize the integrity of the over-all interconnected power systems.

The following criteria for design and operation of interconnected power systems define area generation and transmission requirements. In addition, criteria for determining inter-area transmission transfer capabilities are defined.

Two categories of transmission transfer capabilities are to be considered: normal and emergency. Normal conditions are to be assumed unless an emergency, as defined by Item 2 in the "List of Definitions", exists.

Design studies will assume applicable contractual transfers and the most severe expected load and generation conditions. Operating transfer capability studies will be based on the particular load and generation pattern expected to exist for the period under study. All reclosing facilities will be assumed in service unless it is known that such facilities have been rendered inoperative.

2. GENERATING CAPACITY

Generating capacity will be installed and located in such a manner that after the due allowance for required maintenance and expected forced outages, each area's generating supply will equal or exceed area load at least 99.9615 percent of the time. This is equivalent to a "loss-of-load probability of one day in ten years".

3. AREA TRANSMISSION REQUIREMENTS

The power system should be designed with sufficient transmission capacity to serve area loads under the conditions noted below. The power system should also be operated in such a manner that the design objectives are fulfilled.

3.1 Stability Conditions

Stability of the interconnected power systems shall be maintained during and after the most severe of the conditions stated in a, b, c, d, and e below. Also, the system must be adequate for testing of the outaged element as described in "a" through "e" by manual reclosing after the outage and before adjusting any generation. These requirements will also apply after any critical generator unit, transmission circuit, or transformer has already been lost, assuming that the area generation and power flows are adjusted between outages by use of Five-Minute Reserve.

a. A permanent three phase fault on any generator, transmission circuit, transformer or bus section, cleared in normal time, with due regard to reclosing facilities.

b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple transmission circuit tower, cleared in normal time, with due regard to reclosing facilities.

c. A permanent phase to ground fault on any generator, transmission circuit, transformer,

or bus section with delayed clearing and with due regard to reclosing facilities. This delayed clearing could be due to circuit breaker, relay system or signal channel malfunction.

d. Loss of any element without a fault.

e. A permanent phase to ground fault on a circuit breaker, cleared in normal time, and with due regard to reclosing facilities.

3.2 Steady State Conditions

a. Voltages, line and equipment loadings shall be within normal limits for pre-disturbance conditions.

b. Voltages, line and equipment loadings shall be be within applicable emergency limits for the system load and generation conditions that exist following the disturbance specified in 3.1.

4. TRANSMISSION CAPABILITIES

Transfers of power from one area to another, as well as within areas, should be considered in the design of inter-area transmission and internal area facilities.

Operating capabilities shall be adhered to for normal transfers and transfers during emergencies. These capabilities will be based on the facilities in service at the time of the transfers. In determining the emergency transfer capabilities, it is assumed that a less conservative margin is justified.

Transmission transfer capabilities shall be determined under the following conditions:

4.1 Normal Transfers

4.1.1 Stability Conditions

Stability of the interconnected power systems shall be maintained during and after the most severe of the conditions stated in a, b, c, d, and e below. Also, the system must be adequate for testing of the outaged element as described in "a" through "e" by manual reclosing after the outage and before adjusting any generation.

a. A permanent three phase fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time, with due regard to reclosing facilities.

b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple transmission circuit tower, cleared in normal time, with due regard to reclosing facilities.

c. A permanent phase to ground fault on any generator, transmission circuit, transformer, or bus section with delayed clearing and with due regard to reclosing facilities. This delayed clearing could be due to circuit breaker, relay system or signal channel malfunction.

d. Loss of any element without a fault.

e. A permanent phase to ground fault on a circuit breaker, cleared in normal time, and with due regard to reclosing facilities.

4.1.2 Steady State Conditions

a. For the facilities in service during the transfer, voltages, line and equipment loadings shall be within normal limits.

b. Voltages, line and equipment loadings shall be within applicable emergency limits for the system load and generation conditions that exist following the disturbance specified in 4.1.1.

4.2 Emergency Transfers

4.2.1 Stability Conditions

Stability of the interconnected systems shall be maintained during and after the most severe conditions in "a" and "b" below. System conditions may be adjusted before the outaged element as described in "a" and "b" below is tested.

a. A permanent three phase fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time and with due regard to reclosing facilities.

b. Loss of any element without a fault.

4.2.2 Steady State Conditions

a. For the facilities in service during the transfer, voltages, line and equipment loadings shall be within applicable emergency limits.

b. Voltages, line and equipment loadings shall

be within applicable emergency limits following the disturbance in 4.2.1.

5. POSSIBLE BUT IMPROBABLE CONTINGENCIES

Studies will be conducted to determine the effect of the following contingencies on system performance and plans will be developed to minimize the spread of any interruption that might result.

a. Loss of the entire capability of a generating station.

b. Loss of all lines emanating from a generating station, switching station or substation.

c. Loss of all transmission circuits on a common right-of-way.

d. Permanent three phase fault on any generator, transmission circuit, transformer, or bus section, with delayed clearing and with due regard to reclosing facilities. This delayed clearing could be due to circuit breaker, relay system or signal channel malfunction.

e. The sudden dropping of a large load or major load center.

f. The effect of severe power swings arising from disturbances outside the Council's interconnected systems.

APPENDIX - LIST OF DEFINITIONS

1. AREA

An area is defined as either New Brunswick, New England, New York or Ontario.

2. EMERGENCY

An emergency is assumed to exist in an area if firm load may have to be dropped because sufficient power is unavailable in that area. Emergency transfers are applicable under such conditions.

3. APPLICABLE EMERGENCY LIMITS

These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitation, etc.

Short time emergency limits are those which can be utilized for at least five minutes.

The limiting condition for voltages should recognize that voltages at key locations should not drop below that required for suitable system stability performance, and should not adversely affect the operation of the interconnected systems.

The limiting condition for equipment loadings should be such that cascading will not occur due to operation of protective devices on the failure of facilities.

4. FIVE-MINUTE RESERVE

Five-Minute Reserve is that portion of unused generating capacity which is synchronized to the system, and is fully available within five minutes, plus that portion of capacity available in shut down generating units, in pumped hydro units and by curtailing interruptible loads which is fully available within five minutes.

5. "WITH DUE REGARD TO RECLOSING FACILITIES" is intended to mean that recognition will be given to the type of reclosing: i.e., manual or automatic, and the kind of protective schemes insofar as time is concerned.

6. ELEMENT

An element is defined as a generator, transmission circuit, transformer, circuit breaker or bus section.

APPENDIX G

Date February 10, 1975

System Planning Division

Guides for Planning Area and Regional Supply Facilities

1. Introduction

System Planning Division Procedure No. E1 "Guides for Planning the Main Trunk Transmission System" specifies the reliability requirements for design of the power system. While those criteria apply mainly to the bulk power system where contingencies are more likely to cause loss of a major portion of the East System or jeopardize the interconnected system, they also apply to other parts of the power system where local instability from a fault could cascade into the bulk power system. Studies to check the adequacy of all parts of the system to meet those criteria are normally carried out by those who plan the bulk-power system.

In addition to designing the system as a whole for adequate stability and steady-state operation, it is necessary to design each part of the system for adequate continuity or availability of supply to individual large customers and to transformer stations supplying the distribution system. Criteria for availability are therefore required, particularly for the parts of the system known as Area and Regional Supply Facilities. Such criteria are contained in this Procedure E2.

It is also necessary to provide facilities for maintaining adequate normal and emergency voltages throughout the system. Voltage control is achieved mainly by installation of reactive power sources throughout the system, from generators to distribution capacitors. Voltage criteria will be covered by a separate procedure.

This Procedure E2 is not intended as a set of rigid rules, but rather as a guide towards establishing the minimum availability criteria for the Area and Regional Supply system. Parts of the system may be designed for lower availability, but this should only be done where the stage is temporary, where the reliability requirements of the load are low, or where the cost of the recommended reliability is unjustifiably high. Occasionally a higher availability may be justified, where the load is unusually sensitive or the cost of improvement is low.

Copies of this Procedure are being sent to the Power System Operations Division, with a note emphasizing that it is being used as a guide only, and hence will not be rigidly applied.

Because this Procedure is based primarily on the accumulated experience of the members of System Planning Division, it will be revised as considered necessary. Section Heads and Planning Engineers are asked to use this procedure now on a trial basis and to report any comments or suggestions for change to their Department Head.

2. The Area and Regional Supply System

This comprises all 230 kV and 115 kV circuits supplying step-down transformer stations from 230 kV or 115 kV to 44, 27.6 or 13.8 kV (called LV in the following), the step-down stations themselves, and the 500-115, or 230-115 kV autotransformers and associated switching used for area supply. The high-voltage switching at major stations must be considered not only for its effect on area supply, but also for its effect on system stability.

3. Normal Operation

Normal operation is the condition under which all lines, transformation and switching in the location being studied are in-service. Under these conditions all facilities are to be loaded within their established normal capabilities, and all voltages are to be within their normal range for any condition of load or generation which could reasonably be expected to occur at any time of the year.

4. Emergency Operation

Emergency operation is the condition under which one or more elements of the system are out of service for routine maintenance, or for repair because of a failure. A number of common emergency conditions are listed in Table I. The operating conditions applying during the emergency are determined by the availability level assigned for a particular emergency and a particular size of load. These availability levels are defined in Section 6 below.

In all availability levels except C, it is permissible for the load to be interrupted, but the load must be restored to service within the specified period, depending on the availability level.

At all times during the emergency while load is being supplied, all facilities are to be loaded within their applicable emergency capabilities. This may be either short-term or long-term emergency capability as conditions dictate.

5. Load Level

The availability level required depends on the size of the load. For purposes of Table I, the load level is the peak load in Megawatts for the most critical month for the station or group of stations being studied, for a time about 2 to 5 years hence, depending on the lead-time for the new facilities. It is the load which would be interrupted by the occurrence of the contingency listed. Where "Interruptible" load is supplied from a station, the level of availability required should be discussed with Customer Service Division.

6. Availability Levels

C Continuous supply. This is the highest level. There should be no interruption in supply as a result of the occurrence of the contingency. This level is designated C in Table I.

The voltage may collapse for a few cycles while a fault is being cleared but it must rise immediately after fault clearance, and must be restorable to an acceptable emergency level by automatic action such as on-load tap changers. Transfer of such load to another source is permissible to relieve overload, but the transfer must be done without interrupting the load.

RR Restorable Rapidly. An interruption of 2 seconds is permissible at the time of a contingency or at the later time of load transfer. Restoration within 2 seconds must be accomplished automatically by operation of LV breakers without operator intervention.

RS Restorable by Switching. Load may be interrupted at the time of the contingency, but it must be restorable within one-half hour, for example by the action of a control-room operator using remote or supervisory control, or by use of automatically operated switching at the affected station.

R2 Restorable by Manual Switching. Load may be interrupted at the time of the contingency, but it must be restorable within 2 hours. It is assumed there will be switches, quick-openers or other devices available, which can be operated by a travelling operator or maintenance man to restore service. Means of quickly transferring metering, and relaying will also be required.

R8 Restorable by Maintenance. Load may be interrupted at the time of the contingency, and restoration must be within 8 hours. Restoration is assumed to be the result of repair work or temporary connections which can be made by a maintenance crew. This may comprise such line work as replacement of a pole, crossarm, or insulators, repair of a broken conductor, bypassing a defective switch, or such station work as repair or replacement of a defective low-voltage breaker, connecting of an on-site spare transformer (including metering, relaying, and service supply). Station design must be suitable for transformer connection to be accomplished within 8 hours.

X There is no fixed standard of availability against contingencies marked X. These are treated as "Possible but Improbable Contingencies". Each case must be considered separately, taking into account the probability of occurrence, length of repair time, extent of hardship caused, and cost of providing availability against the contingency. In any specific case the availability will be at a level no higher than R8, and may be as low as to permit the outage to extend for several days.

7. Requirements for Transferring Load

The action to restore supply may be taken either at the location where the fault occurred, thus restoring supply along the normal supply path, or at a remote location to transfer the load to another source. If load is transferred, provision must also be made to transfer it back to the normal supply at a convenient time with minimum interruption.

In the case of transformers and some cables, which have a high short-term overload capability, advantage may be taken of this capacity, provided excess load can be transferred off within the time limit set by the short-term capability.

8. Possible but Improbable Contingencies

No standards are set for availability against more severe contingencies than those listed in Table I because of their low probability of occurrence and the generally very high cost of reliability measures. However, consideration should be given to the effect of these contingencies on specific important loads, and the availability against them should be improved wherever this can be done at reasonable cost.

Some catastrophic contingencies for which there is no minimum standard are:

- Loss of several towers due to windstorm or vehicle impact.
- Simultaneous or overlapping outage of two independent elements, such as outage of a transformer and the line supplying a second transformer at the same station.
- Fire or explosion following a fault.
- Loss of all circuits on the same right of way.
- Loss of a complete station.

Another group of contingencies which can occur, but which are only affected to a limited extent by planning decisions are listed below.

- Errors in design, construction, or operation.
- Failure or misoperation of relaying.
- Failure of supervisory control.
- Faults in station service system.

One type of possible but improbable contingency which will need more consideration in future is the catastrophic outage of several circuits on one right of way. It is likely that in the medium term future there will be narrow rights of way containing heavily-loaded multi-circuit tower lines

with close spacing between lines and shared use of the right of way. In such cases, there is risk of an extended outage to one or more towers of one or more lines due to causes such as:

- Tornadoes
- impact by aircraft
- gas-line explosion
- relocations for highway modifications
- footing damage due to flooding or land slippage.

In the past, it was possible to provide a temporary woodpole bypass circuit on short notice, but such will not be possible on a crowded right of way. Therefore, consideration will have to be given to provision of back-up circuits from a different direction so that part of the load can be restored while repair to the damaged section is carried out. The criteria of Table I require provision of backup to large loads for loss of two circuits, but this backup need not be from a different direction, and can, in fact be from two other circuits of the same multicircuit line.

H P Smith

H.P. Smith
Director of System Planning

February 10, 1975

TABLE I

AREA AND REGIONAL SUPPLY
MINIMUM AVAILABILITY LEVELS

TYPE OF FAULT OR OUTAGE	Load Level of Station or Group Affected By Fault Or Outage (Megawatts) 1 To 15	16 To 40	41 To 75	76 To 150	151 To 250	251 To 500	501 And MORE
Transformer	R8	R2*	RS**	RS	RR	C	C
Overhead Circuit	R8	R8	R8	RS	RR	C	C
Cable Circuit	X	X	R8	RS	RR	C	C
Bus	R8	R2*	R2	R2	R2	C	C
Breaker	R8	R8	R2	R2	R2	R2	R2
Maintain an Element		Same as For Fault					
Two Transformers	X	X	X	X	X	X	X
Double-Circuit Line (Non-Catastrophic)	R8	R8	R8	R8	R8	RS	C
" " " (Catastrophic)	X	X	X	X	X	RS	C
2 ccts of Multicircuit Line	R8	R8	R8	R8	R8	RS	C
Multicircuit Line (Catastrohpic)	X	X	X	X	X	X	X
Two Cables in Same Trench	X	X	X	X	RS	RS	RS
Two Cables Different Trenches	X	X	X	X	X	X	RS
Two Breakers	R8	R8	R8	R8	R8	R8	R2

* Up to 15 MW can be R8
** " " 40 " " " R2

C - Continuous
RR - Restorable Rapidly (LV switching in 2.sec)
RS - Restorable by Switching (30 Min)
R2 - Restorable in 2 Hours by Travelling Operator
R8 - Restorable in 8 Hours by Maintenance Crews
X - No Special Provision

APPENDIX H

AGREEMENT FOR POWER

For Supply of Power to

in the County of

THIS AGREEMENT made in triplicate this day of , 197

BETWEEN:

Ontario Hydro ,

OF THE FIRST PART

- and -

______________________________, hereinafter called the "Customer",

OF THE SECOND PART

WHEREAS the Customer is duly incorporated under the laws of Canada with Head Office at the , in the Province of Ontario, and is operating a plant for the manufactur of on the , in the County of , in the said Province;

AND WHEREAS by Agreement dated between Ontario Hydro and the Customer which Agreement is

hereinafter called "the Agreement" the Customer contracted for a supply of electrical power for use at the said plant during the period and upon the terms and conditions more particularly set forth in the Agreement;

AND WHEREAS Ontario Hydro is willing to supply to the Customer for use at its said plant an additional class of power from those specified in the Agreement, in consideration of which it is desirable that the Agreement be terminated and that a new agreement be entered into by the parties upon the terms and conditions hereinafter appearing.

NOW THEREFORE for and in consideration of the premises and of the mutual agreements set forth and subject to the provisions of The Power Act, R.S.O. 1970, Chapter 354 and amendments thereto, the parties hereto mutually agree as follows:

Section 1 - Definitions:

For the purposes of this Agreement, the following definitions apply:

1.1 "Firm Power" means power made available continuously every day in the year, except as otherwise provided in this Agreement.

1.2 "Firm Contract Demand" means the maximum amount of

Firm Power made available to the Customer during any period.

1.3 "Interruptible Power" means power made available continuously every day in the year, except as otherwise provided in this Agreement, and except that Ontario Hydro shall have the right to suspend the availability of Interruptible Power up to the amount of any Interruptible Contract Demand from time to time as follows:

Interruptible Power Class A

(i) On any Monday, Tuesday, Wednesday, Thursday or Friday in any of the months of March, April, May, June, July, August, September, October and November up to five hours in the day;

(ii) On any Monday, Tuesday Wednesday, Thursday or Friday in any of the months of December, January and February up to fourteen hours in the day; and

(iii) In any month up to fifteen per cent of the total time in the month.

Interruptible Power Class B

(i) In any day of the months of March, April, May, June, July, August, September, October and November up to five hours in the day;

(ii) In any day of the months of December, January and February up to fourteen hours in the day; and

(iii) In any month up to fifteen per cent of the total time in the month.

Interruptible Power Class A and Interruptible Power Class B shall each enable Ontario Hydro to reduce its generation requirements on its power supply system and to provide relief in respect to load requirements on its system where conditions of emergency affect the operation of the system and, in addition, Interruptible Power Class B shall enable Ontario Hydro to effect daily economies in the operation of its system.

1.4 "Interruptible Power Class A Contract Demand" means the maximum amount of Interruptible Power Class A made available to the Customer during any period.

1.5 "Interruptible Power Class B Contract Demand" means the maximum amount of Interruptible Power Class B made available to the Customer during any period.

1.6 "Power" means electrical power and includes energy. It also means Firm Power, Interruptible Power Class A, Interruptible Power Class B or any one or more of those classes of power as the context requires.

1.7 "Day" means each period from twelve o'clock midnight to twelve o'clock midnight next following, Eastern Standard Time, and a "Month" means a calendar month.

1.8 "Total Kilowatt Demand" for any month means the maximum average demand in kilowatts delivered to and taken by the Customer at the point of delivery during any fifteen consecutive minutes in the month subject to correction for power factor as hereinafter provided, namely, that if in the month ninety per cent of the maximum average kilovolt-ampere demand delivered to and taken by the Customer during any fifteen consecutive minutes exceeds the maximum average demand in kilowatts delivered to and taken by the Customer during the said fifteen consecutive minutes then ninety per cent of the said kilovolt-ampere demand expressed in kilowatts shall for billing purposes under this Agreement be deemed to be the Total Kilowatt Demand for the month.

1.9 "Billing Demand of Interruptible Power Class B" for any month means the lesser of -

(i) The Total Kilowatt Demand for the month less the total of the contract demands of Interruptible Power Class A and Firm Power; or

(ii) The Interruptible Power Class B Contract Demand.

1.10 "Billing Demand of Interruptible Power Class A" for any month means the lesser of -

(i) The Total Kilowatt Demand for the month less the total of the Billing Demand of Interruptible Power Class B for the month and the Firm Power Contract Demand; or

(ii) The Interruptible Power Class A Contract Demand.

"Billing Demand of Firm Power" for any month means the Total Kilowatt Demand for the month less the total of the Billing Demands of Interruptible Power Class A and Class B for the month.

1.11 "Billing Month" means any month in which the Customer is required to make a payment for power under this Agreement. Any month in which a Monthly Minimum Payment is required is also a Billing Month.

1.12 "Greatest Total Kilowatt Demand" with respect to any Billing Month means the Greatest Total Kilowatt Demand in any month of this Agreement which does not precede such Billing Month by more than 11 months.

Section 2 - Term of Agreement:

2.1 All of the provisions of this Agreement relating to the supply of and payment for power shall become effective on the date when the Customer takes power to supply a new estimated

load of   which date is hereinafter called the "Commencement Date" and is tentatively fixed as

Except as otherwise provided herein this Agreement shall be in force from year to year commencing on the Commencement Date, but it may be terminated at the end of any such year by sixty days' prior notice in writing from either the Customer or Ontario Hydro to the other.

Section 3 - Supply of Power:

3.1 Subject to the other provisions of this Agreement, Ontario Hydro shall make available and deliver to the Customer power in the amounts of the contract demands set forth in the tabulation in Section 1 of Schedule B attached hereto and made a part hereof. For all purposes of this Agreement it shall be deemed that the order of taking of power is firstly, the Firm Power Contract Demand, secondly, the Interruptible Power Class A Contract Demand, and thirdly the Interruptible Power Class B Contract Demand.

Section 4 - Delivery of Power:

4.1 The power delivered hereunder shall be subject to the provisions set forth in the Terms and Conditions in Schedule A attached hereto and made a part thereof. The point of delivery for power hereunder shall be adjacent to the Customer's property line and shall be at the Ontário Hydro line dead-ending insulator on the Customer's transformer station or line structure at its

plant, which station or line structure as the case may be, shall be located in a location approved by Ontario Hydro. When delivered at such point of delivery power shall be at a nominal frequency of 60 hertz and at a nominal voltage of volts. For the purposes of this Agreement, power means electrical power and includes energy.

Section 5 - Interference with Availability of Power:

5.1 Ontario Hydro shall have the right to interrupt the supply of power at any time to the Customer to such extent as is necessary for the purpose of safeguarding life or property or for the purpose of construction, maintenance, operation, repair, replacement or extension of the equipment or works of Ontario Hydro. Ontario Hydro shall limit the duration of such interruptions so far as it is practicable to do so and, except in emergencies, shall give adequate warning of its intention to interrupt the supply to the Customer.

5.2 If Ontario Hydro's inability to make available power or the Customer's inability to use power is in either case attributable to an Uncontrollable Event or the power is interrupted by Ontario Hydro for any of the purposes described in Section 5.1, then neither party shall be liable to the other for damages or breach of contract. The term "Uncontrollable

Event" shall be deemed to be a cause reasonably beyond the control of the party whose inability as aforesaid is involved such as, but without limitation to, strike of that party's employees, damage or destruction by the elements, accident to the works of that party, fire, explosion, war, the Queen's enemies, legal acts of the public authorities, insurrection, Act of God, or inability to obtain essential services or to transport materials, products or equipment because of the effect of similar causes on that party's suppliers or carriers. If such inability or interruption prevails for at least twenty-four consecutive hours within any month, an adjustment in the payment of power for the month shall be allowed by reducing the Billing Demand for the month.

The amount of the reduction in kilowatts shall be determined by multiplying the Billing Demand for the month less the average amount of power in kilowatts taken by the Customer in the period of that month during which the said inability or interruption prevails, by the ratio of the number of periods of twenty-four consecutive hours during which the said inability or interruption prevails to the number of days in that month. If such inability or interruption prevails for at least twenty-four consecutive hours in the month, then the Customer shall not be obligated to pay the Monthly Minimum Payment in Section 4 of Schedule B for such month.

5.3 No adjustment in the payment for power for a month shall be allowed because Ontario Hydro exercises its right to suspend the availability of any or both classes of Interruptible Power, such rights of suspension having been recognized in the rates for Interruptible Power.

Section 6 - Rates:

6.1 The Customer shall pay Ontario Hydro monthly for power made available under this Agreement in accordance with the provisions of this Agreement including the rates and provisions of Schedule B.

6.2 Ontario Hydro may change its rates at any time by written notice to the Customer; provided that there shall not be more than one rate change within a period of twelve consecutive months. Such notice shall be given at least sixty days prior to the effective date of the rate change.

If the Customer fails to notify Ontario Hydro within thirty days after the date of any such notice that the Customer does not accept the change in rates, this Agreement shall remain in force with the rates change in accordance with

the notice given by Ontario Hydro, but subject otherwise to the same terms and conditions. If the Customer notifies Ontario Hydro that it does not accept the change in rates within the time hereinbefore stipulated either party may terminate this Agreement on, or at any time after, the effective date of the change in rates specified in the notice of change in rates by giving to the other party at least ten days prior notice of termination; provided, however, that if the Customer takes any power on or after the effective date of the change in rates, such power shall be paid for at the changed rates.

Section 7 - Change in Availability of Power:

7.1 The maximum amount of power to be made available to the Customer by Ontario Hydro hereunder may be changed from time to time by agreement of the parties. If agreement is reached Schedule B hereto shall be amended accordingly and shall become applicable without further action by the parties.

7.2 The Customer would be well advised to give Ontario Hydro at least eighteen months notice of any request to change materially the amounts of power specified in Schedule B although Ontario Hydro shall use its best efforts to accommodate any reasonable request by the Customer.

Section 8 - Excess taking of power:

8.1 If in any month the Customer takes power so that the Billing Demand for that month exceeds the Contract Demand for that month then such excess shall be excess demand and shall be paid for at the effective rate for such excess demand, but the obligation to make payment for such excess demand shall not entitle the Customer to take excess demand in any month.

Section 9 - Suspension of Interruptible Power:

9.1 Whenever practicable Ontario Hydro will give the Customer preliminary warning of the probable scheduling of suspensions of availability of Interruptible Power.

9.2 Ontario Hydro will give a notice of each suspension and the Customer shall reduce its use of Interruptible Power to the amount and at the time requested by such notice. A notice of suspension may require an immediate reduction of taking of Interruptible Power or may provide for a period of time for compliance with such notice.

9.3 For purposes of determining the Customer's compliance with its obligation to reduce its takings and the use of Ontario Hydro's rights of suspension, each period of suspension shall commence at the time designated in the notice of suspension and shall end at the time designated in the notice of resumption of availability of Interruptible Power, and each such period is hereinafter called a "Reduction Period". The expression "Reduction Period" shall have a corresponding meaning when used in the plural.

9.4 Any warning or notice provided for in this Section may be given orally or by the use of electric signalling equipment if the parties agree to use such equipment. The records of Ontario Hydro's operator pertaining to any warning or notice shall be deemed to be conclusive evidence of the warning or notice having been given to the Customer and of

all the terms and conditions stated in any notice Any oral warning or notice may be given by an operator of Ontario Hydro to such operator of the Customer at its plant as the Customer shall designate in writing to Ontario Hydro forthwith after execution of this Agreement, but failing such designation or in the event of the person so designated not being immediately available, any warning or notice may be given to any other employee of the Customer at its plant.

<u>Section 10 - Customer's Failure to Comply:</u>

10.1 The Customer shall operate in compliance with each notice given under Section 9 with respect to suspension of availability of Interruptible Power.

10.2 Where in any month the Customer fails to comply with a notice requiring it to reduce its total takings of power hereunder during any Reduction Period the Customer shall pay to Ontario Hydro in addition to all other charges that may be payable in the month, an additional charge determined by applying one-half of the Demand Rate for Firm Power to the greatest difference in any of the reduction periods for the month between (i) the maximum average demand in kilowatts of power taken by the Customer during any fifteen consecutive minutes in a Reduction Period, and (ii) the amount to which any

such notice shall have required the Customer to reduce its said takings during that Reduction Period; but the provisions of this sentence shall not apply to any month where in each Reduction Period the Customer's total takings of power at no time during such reduction Period shall have exceeded an amount of power equal to the amount to which the notice shall have required the Customer to reduce its total takings of power during that Reduction Period plus five per cent of the Firm Power Contract Demand. Where the provisions of the preceding sentence are applicable for billing purposes for any month and where in that month or in any subsequent month during the next ensuing period of twelve consecutive months the Customer fails to comply with a notice requiring it to reduce its total takings of power during any Reduction Period the Customer shall pay to the Commission in addition to all other charges that may be payable for power in the month, an additional charge determined as provided for in the next preceding sentence but by applying the full demand rate for Firm Power in lieu of applying one-half of that rate.

10.4 Without limiting or affecting the foregoing provisions of this Section, failure by the Customer to comply with any notice requiring it to reduce its takings of power is a failure to perform an obligation affecting operation and Section 9 of

the Terms and Conditions applies accordingly.

Section 11 - Customer's Premises:

11.1 One or more representatives of Ontario Hydro appointed for the purposes of this section may at any reasonable time during the continuance of this Agreement, have access to the premises of the Customer for the purpose of inspecting the electrical works and electrical records of the Customer and taking copies from the latter as required and creating its own electrical records; and may do any of these things.

11.2 Notwithstanding anything in this Agreement, no officer, servant or agent of Ontario Hydro shall be entitled to enter upon the lands or premises of the Customer without first obtaining from the Customer permission so to do in accordance with the Customer's security requirements, but if at any time such permission is refused or delayed and by reason thereof Ontario Hydro is prevented from fulfilling any obligation under this Agreement, then Ontario Hydro shall not be liable in damages for failure to perform the said obligation and provided further that if by reason of such permission being refused or delayed as aforesaid Ontario Hydro is prevented from fulfilling its obligations with respect to the supply of power to any person or persons other than the Customer, then the

Customer shall indemnify Ontario Hydro against all claims and demands arising in any manner therefrom.

11.3 The Customer hereby grants to Ontario Hydro the right at all times during the continuance of this Agreement to use, free of charge or rent, as much of the Customer's lands as Ontario Hydro may deem necessary for the supply of power to the Customer hereunder, the location of the lands required for such purpose to be mutually satisfactory to Ontario Hydro and the Customer, and where any transmission line, plant or equipment of Ontario Hydro is situate on the said lands for the supply of power to the Customer, the right at all times to use the said transmission line, plant or equipment, free of charge or rent, in order to supply power to another customer or other customers of Ontario Hydro, and the right to do everything reasonable in connection with the said transmission lines, plant or equipment of Ontario Hydro which Ontario Hydro from time to time may reasonably require for the purposes aforesaid including the right to trim or remove trees and brush where Ontario Hydro considers it necessary to do so for the protection or operation of its works. The Customer agrees to keep its structures, machinery, plant and works at such distance from Ontario Hydro's power supply facilities as will permit the safe and efficient maintenance and operation of those facilites. If the Customer requires relocation of any of Ontario Hydro's

works and facilities, the Customer shall furnish on its lands another location satisfactory to Ontario Hydro. Ontario Hydro will perform the work of relocation and the Customer will pay the cost thereof to the extent that such works and facilities are used for supply of power to the Customer. Ontario Hydro shall have the right at any time prior to the expiration of ninety days notice in writing from the Customer delivered after the termination of this Agreement to remove from the premises of the Customer any and all apparatus, equipment and works which may have been installed by Ontario Hydro upon such premises for the supply of power to the Customer or other customers hereunder.

Section 12 - Notices:

12.1 Any written notice required by this Agreement shall be deemed properly given if either mailed or delivered to the Secretary, Ontario Hydro, 700 University Avenue, Toronto, Ontario, M5G 1X6 on behalf of Ontario Hydro, or to

, on behalf of the Customer. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

Section 13 - The Agreement:

13.1 The Agreement shall be deemed terminated as of the Commencement Date.

IN WITNESS WHEREOF Ontario Hydro and the Customer have caused this Agreement to be executed by the affixing of their corporate seals attested by the signatures of their proper officers duly authorized in that behalf.

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SCHEDULE A - Forming part of the Agreement dated the

day of 19 , between Ontario Hydro

and

which parties are referred to in the said Agreement and in this Schedule as "Ontario Hydro" and the "Customer", respectively.

TERMS AND CONDITIONS

1. Conditions of Supply

The power delivered at any point of delivery shall be three phase alternating current at the nominal frequency and the nominal voltage specified in the Agreement. Except for abnormal operating conditions, variations from any nominal frequency or nominal voltage shall not exceed appropriate ranges of tolerable values. Customer shall be responsible for installing protective equipment to protect its own property and operations from variations in frequency and voltage or from temporary delivery of other than three phase power. In no event shall Ontario Hydro be liable to Customer for any loss, damage or injury resulting directly or indirectly from variations in frequency or voltage or for temporary delivery of other than three phase power or any of them.

The maintenance by Ontario Hydro of the nominal frequency and nominal voltage at the point of delivery shall constitute the supply of power and fulfillment of all the operating obligations

of Ontario Hydro respecting delivery of power. When the voltage and frequency are maintained as specified, the amount of power taken, its distribution as to phases (except to the extent that inequality of such distribution is caused because the no-load voltage between phases at the point of delivery are unequal) its fluctuations, load factor and power factor are under the sole control of the Customer.

Ontario Hydro will exercise reasonable diligence to provide a regular and uninterrupted supply of power in accordance with the terms of the Agreement, but nothing contained in the Agreement shall be construed as obligating Ontario Hydro to guarantee such continuity of power supply, and Ontario Hydro shall not be liable to the Customer in damages for any failure to maintain such supply howsoever caused.

2. Metering

Ontario Hydro shall provide, install and maintain the meters and associated equipment which are needed to determine the amounts of power and energy used by the Customer. If requested by Ontario Hydro, the Customer shall provide a safe and reasonable location free of charge on the Customer's premises for the installation and maintenance of Ontario Hydro's measuring equipment.

Access to any measuring equipment and to any other apparatus, equipment and works belonging to Ontario Hydro and situated on the premises of the Customer, shall be free to the representatives of Ontario Hydro at any reasonable time for the purpose of inspection, operation, test, adjustment, repair, alteration, reconstruction and removal.

If in Ontario Hydro's judgment there are special conditions which must be met in the Customer's station or switchgear with respect to measuring equipment, the Customer shall at its own expense provide, install and maintain in accordance with plans and specifications approved by Ontario Hydro, that part of the associated equipment necessary in Ontario Hydro's judgment for the installation and operation of Ontario Hydro's meters.

If the measuring equipment is not connected at a point of delivery defined in the Agreement, all amounts so metered shall be appropriately adjusted to give results such as would be obtained by measuring equipment connected at the point of delivery. If for any period the measuring equipment or any part thereof is not in service, the consumption during such period shall be determined from the best information available.

If requested by the Customer Ontario Hydro shall arrange for the testing and inspection of its measuring equipment by a

person qualified to do so. If such tests show that the measurements are accurate within the limits prescribed by law, the cost of making such tests or inspections shall be paid by the Customer. If any tests or inspections show Ontario Hydro's measurements to be inaccurate by more than the limits prescribed by law an offsetting adjustment shall be made in the Customer's bills for any known or agreed period of inaccuracy; in the absence of such knowledge or agreement the adjustment shall be limited to thirty days prior to the date of such tests. Any Ontario Hydro measuring equipment found to be inaccurate by more than the limits of accuracy prescribed by law shall be promptly replaced, repaired or readjusted by Ontario Hydro.

If requested by Ontario Hydro the Customer shall take the records or charts from the measuring equipment at such reasonable times as Ontario Hydro may require. The Customer shall indicate the time of taking and the date on any record or chart or on the form supplied by Ontario Hydro for such purpose and forward the records or chart and form to Ontario Hydro promptly.

3. Resale of Power

The power supplied is for the use of the Customer in the operation of its facilities at the locations specified in the Agreement and shall not be resold or otherwise disposed of directly or indirectly, without the written consent of Ontario Hydro.

4. Billing

Ontario Hydro will bill the Customer for all payments required to be made for power under the Agreement during the preceding calendar month as soon thereafter as practicable. The Customer shall pay such bill within ten days after the date of the bill. Interest shall be payable on any amount so billed and remaining unpaid ten days after billing at the effective rate of interest set by Ontario Hydro from time to time for unpaid accounts and in any event, not less than six per cent per annum. If any bill remains unpaid for thirty days after the date of the bill, Ontario Hydro may, in addition to all other remedies available to it, and after giving to the Customer at least ten days notice in writing of Ontario Hydro's intention to do so, discontinue the supply of power and may refuse to resume delivery so long as any past due bill remains unpaid.

5. Power Factor

The Customer shall take and use power in such manner that the ratio of the kilowatts to the kilovolt-amperes when measured simultaneously is as near unity as practicable.

6. Phase Balancing

The Customer shall take and use the power so that the current will be taken from the three phases equally as far as

practicable. If at any time the unbalance in current is in Ontario Hydro's judgment excessive, the Customer agrees to make at its own expense, upon request, the changes necessary to reduce the unbalance to an acceptable value.

7. Customer's Equipment

The Customer agrees to provide suitable transforming equipment and all other electrical equipment from the point or points of delivery of the power including electrical equipment Ontario Hydro deems necessary from time to time during the continuance of the Agreement for the safety and security of the operation of Ontario Hydro's power supply system. All of the said equipment of the Customer shall be subject to the approval of Ontario Hydro, and shall be installed, maintained and operated in a manner satisfactory to Ontario Hydro. Until such approval has been given, Ontario Hydro shall not be bound to deliver any power under the Agreement or, if delivery has commenced, to continue such delivery.

8. Electrical fluctuations and interference

The Customer shall operate in such a manner so as not to cause disturbance or fluctuations on Ontario Hydro's power system or interference with communication systems or control circuits of Ontario Hydro or of any other third party. The Customer shall take such remedial measures at its own expense by way of installing suitable apparatus or otherwise as may be

necessary to reduce any disturbance or fluctuations on Ontario Hydro's power system or any interference with the communication systems or control circuits of Ontario Hydro or of any third party to a tolerable level. In any event, the Customer shall indemnify Ontario Hydro from all claims and demands made against Ontario Hydro by any third party in consequence of failure by the Customer to perform its obligations under this section.

9. Customer's operation

If at any time the Customer fails to perform any of its obligations affecting operation under this Agreement including, without limiting the generality of the foregoing, taking power in excess of any maximum amount specified in this Agreement, or of any limit of amount then in force, or failing to operate as required by this Agreement, then Ontario Hydro may give notice thereof to the Customer, which notice may be given by telephone to an employee of the Customer by an employee of Ontario Hydro, and the Customer shall immediately remedy the said failure. In case of continued failure for more than fifteen minutes after the notice, Ontario Hydro may discontinue delivery to the Customer of all power or of any part thereof and shall not be obliged to resume delivery until the Customer shall have remedied the failure. The Customer shall forthwith designate in writing to Ontario Hydro the name of the employee to whom notices under this clause are to

be given, and in default of such designation or in the event of the said employee not being immediately available to receive any such notice, it may be given by telephone or otherwise to any other employee of the Customer.

10. Customer in default

If the Customer fails to perform any obligation under this Agreement Ontario Hydro may give written notice to the Customer that unless the obligation is completely fulfilled within a specified period after the mailing of the notice Ontario Hydro will discontinue delivery of power to the Customer. If the Customer continues in default in respect of the obligation beyond the period specified in the notice Ontario Hydro may discontinue delivery of power and may refuse to resume delivery until the Customer has fulfilled its obligation. The right to discontinue supply of power in this section is in addition to and not-in limitation of any other right provided elsewhere in this Agreement to discontinue supply of power forfailure of the Customer to perform a particular obligation.

11. Discontinuance of Supply

Notwithstanding that Ontario Hydro has discontinued the supply of power to the Customer by reason of failure by the Customer to perform any of its obligations under this Agreement, or that

Ontario Hydro has discontinued such supply upon the request of the Customer, such discontinuance shall not be construed as a breach of contract by Ontario Hydro to make available and deliver power to the Customer under the terms of the Agreement, nor shall such discontinuance relieve the Customer from its obligations to pay for power in accordance with the provisions of the Agreement, and such provisions shall continue in force until termination of the Agreement, unless Ontario Hydro otherwise agrees in writing.

12. Termination for Default

If after Ontario Hydro has discontined supply of power for failure by the Customer to perform any of its obligations under the Agreement the Customer continues in default in respect of the obligation, Ontario Hydro may at its option give written notice to the Customer that unless the obligation is completely fulfilled within a specified period (not less than ten days) after the mailing of the notice, the Agreement will be deemed terminated. If the Customer continues in default in respect of the obligation beyond the period specified in the notice, the Agreement shall thereupon terminate. Such termination shall be without waiver of any amounts which may be due or of any rights including the right to damages for such breach which may have accrued up to and including the date of such termination.

13. Automatic Reclosing

Where Ontario Hydro has installed, on its facilities for supply of power to the Customer hereunder, equipment for automatic reclosing of circuit breakers after an interruption of power supply, so as to improve, within feasible limits, continuity of such supply, it shall be the obligation of the Customer to provide, at its own expense, (i) adequate protective equipment for all electrical apparatus of the Customer that might be adversely affected by Ontario Hydro's reclosing equipment, and (ii) such equipment as may be required for the prompt disconnection of any apparatus of the Customer that might affect proper functioning of Ontario Hydro's reclosing equipment. Ontario Hydro will co-operate with the Customer and use its best endeavours with a view to mutual agreement as to the reclosing time of Ontario Hydro's equipment, but failing such agreement the decision of Ontario Hydro as to that time shall be final.

14. Liability

The Customer shall assume all risk, liability or obligation in respect to:

(a) all damage to property of Ontario Hydro on the lands and premises of the Customer, to the degree that such damage shall have been due to the negligence of the Customer, its servants or agents; and

(b) all loss, damage or injury to property of the Customer or property of any third person on the said lands and premises, or to any person or persons (including loss of life) on the said land and premises, excluding injury to or death of any employee or agent of Ontario Hydro, which shall have been due to power supplied to the Customer or due to the said property of Ontario Hydro to the extent used to supply power to the Customer, except to the degree that such loss, damage or injury shall have been due to the negligence of Ontario Hydro, its servants or agents.

The Customer shall indemnify Ontario Hydro and save it harmless from all liability assumed by the Customer under this section, and all claims or demands in connection therewith.

15. Waiver

Any failure by either Ontario Hydro or the Customer to exercise any right or enforce any remedy under this Agreement shall be limited to the particular instance, and shall not be deemed to waive any other right or remedy or affect the validity of this Agreement. The exercise by either party of any remedy hereunder shall not be deemed to waive any other remedy that such party may have, and such remedies may be exercised and continued concurrently or separately.

16. Arbitration

In case of any dispute between Ontario Hydro and the Customer relative to anything contained in or arising from this

Agreement, and where the dispute cannot be resolved by the parties themselves, the dispute shall be submitted to arbitration under The Arbitrations Act of Ontario, and the provisions of that Act shall apply accordingly, but either party, if dissatisfied with the award of the arbitrator or arbitators, may move to set aside the award, or may appeal from the award.

17. Successors and Assigns

This Agreement shall extend to, be binding upon and enure to the benefit of Ontario Hydro and of the Customer and their respective successors and assigns provided that the Customer shall not be entitled to assign its entire interest in this Agreement or any portion thereof without the consent in writing of Ontario Hydro.

SCHEDULE B - Forming part of the Agreement dated the day of , 19 , between Ontario Hydro , which parties are referred to in the said Agreement and in this Schedule as "Ontario Hydro" and the "Customer" respectively.

1. Availability of Power

Firm Power	kilowatts
Interruptible Power Class A	kilowatts
Interruptible Power Class B	kilowatts

2. Monthly Payment

Subject to the provisions relating to the monthly minimum payment below, the monthly payment for power for any month shall be the total of the Demand Charge for the month and the Energy Charge for the month determined according to the schedule of rates in Section 3 next following.

3. Rates

The following schedule of rates is applicable:

(a) The Energy Charge for the month shall be a charge at the energy rate of cents per kilowatt hour for all energy taken for the month.

(b) The Demand Charge for the month shall be the total of -

(i) A charge at the demand rate of Firm Power of per kilowatt per month for each kilowatt of the Billing Demand of Firm Power up to the amount of Firm Power Contract Demand; and

(ii) A charge at the demand rate of per kilowatt per month for the excess demand of the Billing Demand of Firm Power over the Firm Power Contract Demand; and

(iii) A charge at the demand rate of Interruptible Power Class A of per kilowatt per month for the Billing Demand of Interruptible Power Class A; and

(iv) A charge at the demand rate of Interruptible Power Class B of per kilowatt per month for the Billing Demand of Interruptible Power Class B.

4. Monthly Minimum Payment

The minimum payment required to be made by the Customer each month for power under this Agreement shall be for the first month commencing on the Commencement Date the total of the charges under paragraph (a) next following and for any month after the first month shall be the greater of the totals determined under either paragraph (a) or (b).

(a) The total of

(i) An Energy Charge at the energy rate of cents per kilowatt hour for all energy taken in the billing month; and

(ii) A charge at the demand rate of Firm Power of per kilowatt per month for ten per cent of the amount of Firm Power Contract Demand; and

(iii) A charge at the demand rate of Interruptible Power Class A of per kilowatt per month for ten per cent of the amount of Interruptible Power Class A Contract Demand; and

(iv) A charge at the demand rate of Interruptible Power Class B of per kilowatt per month for ten per cent of the amount of Interruptible Power Class B Contract Demand.

(b) The total of

(i) An Energy Charge at the energy rate of cents per kilowatt hour for all energy taken in the billing month; and

(ii) A charge at the demand rate of Firm Power of per kilowatt per month for seventy-five per cent of the Billing Demand of Firm Power for that month in which the Greatest Total Kilowatt Demand was established; and

(iii) A charge at the demand rate of Interruptible Power Class A of per kilowatt per month for seventy-five per cent of the Billing Demand of Interruptible Power Class A for that month in which the Greatest Total Kilowatt Demand was established; and

(iv) A charge at the demand rate of Interruptible Power Class B of per kilowatt per month for seventy-five per cent of the Billing Demand of Interruptible Power Class B for that month in which the Greatest Total Kilowatt Demand was established.

Whenever the rates for power are changed, this Section 4 shall be applied as if the new rates were substituted for the rates changed.

(a) The total of -

(i) An Energy Charge at the energy rate of cents per kilowatt hour for all energy taken in the Billing Month; and

(ii) A charge at the demand rate of Firm Power of $ per kilowatt per month for ten per cent of the amount of the Firm Power Contract Demand; and

(iii) A charge at the demand rate of Interruptible Power Class "A" of $ per kilowatt per month for ten per cent of the amount of the Interruptible Power Class "A" Contract Demand.

(b) The total of -

(i) An Energy Charge at the energy rate of cents per kilowatt hour for all energy taken in the Billing Month; and

(ii) A charge at the demand rate of Firm Power of $ per kilowatt per month for seventy-five per cent of the Billing Demand of the Firm Power for that month in which the Greatest Combined Kilowatt Demand was established; and

(iii) A charge at the demand rate of Interruptible Power Class "A" of $ per kilowatt per month for seventy-five per cent of the Billing Demand of the Interruptible Power Class "A" for that month in which the Greatest Combined Kilowatt Demand was established.

Whenever the rates for power are changed, this Section 4 shall be applied as if the new rates were substituted for the rates changed.

APPENDIX I

230 kV Transmission Line Work

Circuit Designation	Line Section	Approx. Line Length (km)	Work Involved	Estimated Cost ($)
C3S	Chats Falls GSx South March TS	39	Reconductored 39 km with 1.34" compact conductor. Raise 38 towers by extensions. Replace 2 towers.	2 600 000
M32S	South March TS x Merivale TS	15	Reconductored 15 km with 1.34" compact conductor. Raised 20 towers by extensions. Replaced 1 tower.	1 700 000
L24A	St. Lawrence TS x Hawthorne TS	76	Reconductored with 1.6" compact conductor for 71 km. Reconductored with 1.6" ACSR conductor for 5 km. Replaced 1 heavy anchor structure. Replaced 4 two pole suspension structures. Raise about 75 towers by extensions.	6 400 000
B31L	St. Lawrence TS x Interprovincial Boundary Jct.	47	Reconductor with 1.34" compact conductor. Raise 7 towers by extensions. Replace 2 towers.	2 200 000
B5D	Interprovincial Boundary Jct. x St. Isidore TS.	39	Reconductor with 1.34" compact conductor. Replace 2 Towers	2 200 000

115 kV Transmission Line Work

Circuit Designation	Line Section	Approx. Line Length (km)	Work Involved	Estimated Cost ($)
B5QK	Cataraqui TS x Railton Jct. x Barrett Chute GS	119	Reconductored 1 km with 795 kcmil conductor. Replaced 2 wood pole structures	50 000
C7BM	Barrett Chute GS x Chats Falls GS x Ottawa Woodroffe TS x Merivale TS	95	Reconductored 1 km with 795 kcmil conductor. Replace 293 wood pole structures.	1 600 000
W6MC	Stewartville GS x Chats Falls GS x Merivale TS	68	Some retensioning. Replace 64 wood pole structures.	430 000

230 kV Station Uprating

STATION	Estimated Cost ($)
Chats Falls GS	2 200 000
Hawthorne TS	400 000
St. Isidore TS	370 000
St. Lawrence TS	1 200 000
South March TS	318 000

115 kV Station Uprating

STATION	Estimated Cost ($)
Barrett Chute GS	50 000
Cataraqui TS	12 000
Chenaux GS	3 000
Napanee TS	29 000
Stewartville GS	40 000

Reactive Power Sources

	Estimated Cost ($1979)
At various stations in the period starting in 1980 onward. This assumes that all sources are shunt capacitors.	18 900 000